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The Northeast Utilities System

Robert A. Bersak
Assistant Secretary
and Assistant General Counsel

March 25, 2005

Ms. Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
Eight Old Suncook Road
Concord, New Hampshire 03301-7319

Re: *Docket No. DE 04-177 - Public Service Company of New Hampshire – Rate Case*
Proposed Transition Service Energy Rate - - ROE Proceeding

Dear Secretary Howland:

Pursuant to Rule Puc 203.09, enclosed for filing in Docket No. DE 04-177 is the direct testimony of Dr. Roger A. Morin on behalf of Public Service Co. of New Hampshire.

I certify that copies of this filing are being provided to parties on the service list of this docket pursuant to the Commission's rules.

Thank you for your attention to this filing. If you have any questions, please contact me.

Very truly yours,

Robert A. Bersak
Assistant Secretary and
Assistant General Counsel

cc: Service List

SERVICE LIST – DE 04-177

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THE STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Docket No. DE 04-177

DIRECT TESTIMONY OF

Dr. Roger A. Morin

on behalf of

Public Service Co. of New Hampshire

March 25, 2005

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INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Professor of Finance at the College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The Management Exchange Inc. and Exnet, where I continue to conduct frequent national executive-level education seminars throughout the United States and Canada. In the last twenty five years, I have conducted numerous national seminars on “Utility Finance,” “Utility Cost of Capital,” “Alternative Regulatory Frameworks,” and on “Utility Capital

Allocation," which I have developed on behalf of The Management Exchange Inc. in conjunction with Public Utilities Reports, Inc.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utility Fortnightly. I published a widely-used treatise on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports, Inc., Arlington, Va. 1984. My more recent book on regulatory matters, Regulatory Finance, is a voluminous treatise on the application of finance to regulated utilities and was released by the same publisher in late 1994. The next edition is forthcoming in 2005. I have engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management and corporate litigation. Exhibit RAM-1 describes my professional credentials in more detail.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON COST OF CAPITAL BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes, I have been a cost of capital witness before more than forty (40) regulatory bodies in North America, including the Federal Energy Regulatory Commission, and the Federal Communications Commission. I have also testified before the following state, provincial, and other local regulatory commissions:

Alabama	Illinois	Nevada	Oregon
Alaska	Indiana	New Brunswick	Pennsylvania
Alberta	Iowa	New Jersey	Quebec
Arizona	Kentucky	New York	South Carolina
Arkansas	Louisiana	Newfoundland	South Dakota
British Columbia	Manitoba	North Carolina	Tennessee
California	Michigan	North Dakota	Texas
Colorado	Minnesota	Nova Scotia	Utah
District of Columbia	Mississippi	Ohio	Vermont
Florida	Missouri	Oklahoma	Washington
Georgia	Montana	Ontario	West Virginia
Hawaii			

The details of my participation in regulatory proceedings are provided in Exhibit RAM-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present an independent appraisal of the fair and reasonable rate of return on the power generation operations of Public Service Company of New Hampshire (“PSNH” or the “Company”) in the State of New Hampshire, with particular emphasis on the fair return on the Company’s common equity capital committed to that business. Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would: (1) be fair to the customer, (2) allow the Company to attract capital on reasonable terms, (3) maintain the Company’s financial integrity, and (4) be comparable to returns offered on comparable risk investments. I will testify in this proceeding as to that opinion.

Q. PLEASE BRIEFLY IDENTIFY THE EXHIBITS AND APPENDICES ACCOMPANYING YOUR TESTIMONY.

A. I have attached to my testimony Exhibits RAM-1 through RAM-15 and Appendices A and B. These Exhibits and Appendices relate directly to points in my testimony, and are described in further detail in connection with the discussion of those points in my testimony.

Q. PLEASE SUMMARIZE YOUR FINDINGS CONCERNING PSNH'S COST OF COMMON EQUITY.

A. I recommend that a rate of return of 11.4% be used for ratemaking purposes on PSNH's common equity capital devoted to its power generation business in the State of New Hampshire.

My recommendation is derived from a two-step methodology. First, I estimated the cost of common equity capital to an average risk vertically integrated electric utility using the Capital Asset Pricing Model ("CAPM"), Risk Premium, and Discounted Cash Flow ("DCF") methodologies. The results of those various methodologies indicate that the cost of common equity capital to a typical vertically integrated utility such as PSNH is 11.0% overall for the "bundled" vertically integrated utility.

Second, I estimated the cost of common equity capital to PSNH's power generation business based on the risk differential between the power generation business and the electricity transmission/distribution ("T&D", or "wires") business which I estimate to be 86 basis points. The implied return differential between the power generation business and the vertically integrated electric utility is 43 basis points, given the relative equal importance of the T&D and generation segments. In order to appraise the difference in risk and return between the T&D business and the power generation business, I relied on the CAPM. My recommended risk differential is derived from divisional cost of capital analyses on several surrogates for the T&D and generation segments, including distribution utilities, diversified energy utilities, and proxies for the power production business.

My recommended rate of return reflects the application of my professional judgment to the various results in light of the indicated returns from my Risk Premium, CAPM, DCF, and divisional cost of capital analyses.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. The remainder of my testimony is divided into four (4) sections:

(i) Regulatory Framework and Rate of Return;

(ii) Cost of Equity Estimates;

(iii) Risk-Return Differentials; and

(iv) Summary and Recommendation.

The first section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. The second section contains the application of CAPM, Risk Premium, and DCF tests in order to estimate the cost of common equity capital for a typical vertically integrated electric utility company. The third section discusses the theory underlying the methodologies used in quantifying the risk-return differential between the T&D and the power generation businesses, and presents the results from the various methodologies. In the final section, the results from the various approaches are summarized.

I. REGULATORY FRAMEWORK AND RATE OF RETURN

Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR ASSESSMENT OF THE COST OF COMMON EQUITY?

A. Two fundamental economic principles underlie the appraisal of the cost of equity, one relating to the supply side of capital markets, the other to the demand side. According to the first principle, a rational investor is maximizing the performance of his portfolio only if he expects the returns earned on investments of comparable risk to be the same. If not, the rational investor will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract the capital funds it needs to meet its service demands and to maintain financial integrity unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk. On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments exceeds or equals the company's cost of capital. This concept suggests that a regulatory commission should set rates at a level sufficient to create equality between the return on physical asset investments and the company's cost of capital.

Q. UNDER TRADITIONAL COST OF SERVICE REGULATION, PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES SHOULD BE SET.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company recovers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable the company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, investors' required rate of return, is more difficult to estimate. It is the purpose of the next section of my testimony to estimate PSNH’s cost of common equity capital.

Q. WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR RETURN ON COMMON EQUITY?

A. The basic premise is that the allowable return on equity should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness and ability to attract capital on reasonable terms. The attraction of capital standard focuses on investors' return requirements that are generally determined using market value methods, such as the Risk Premium, CAPM, or DCF methods. These market value tests define fair return as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternative investments of comparable risk.

Q. WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION OF A FAIR AND REASONABLE RATE OF RETURN ON COMMON EQUITY?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1. Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).
2. Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944).

The Bluefield case set the standard against which just and reasonable rates of return are measured:

> "*A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public* *equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties* *... The* *return should be reasonable*, *sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to* *maintain and support its credit and enable it to raise money* *necessary for the proper discharge of its public duties*." (Emphasis added)

The Hope case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the Bluefield case and recognized that revenues must cover "capital costs." The Court stated:

> "*From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock ... By that standard the* *return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks*. *That return, moreover, should be sufficient to* *assure confidence in the financial integrity* *of the enterprise, so as to maintain its credit and attract capital*." (Emphasis added)

The United States Supreme Court reiterated the criteria set forth in Hope in Federal Power Commission v. Memphis Light, Gas & Water Division, 411 U.S. 458 (1973), in Permian Basin Rate Cases, 390 U.S. 747 (1968), and most recently in Duquesne Light Co. vs. Barasch, 488 U.S. 299 (1989). In the Permian cases, the Supreme Court stressed that a regulatory agency's rate of return order should:

> "*...reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed…*"

Therefore, the "end result" of this Commission's decision should be to allow PSNH the opportunity to earn a return on equity that is: (1) commensurate with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in the company's financial integrity, and (3) sufficient to maintain the company's creditworthiness and ability to attract capital on reasonable terms.

Q. HOW IS THE FAIR RATE OF RETURN DETERMINED?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the Company. It is the composite weighted cost of the various classes of capital (bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. The fair return in dollars is obtained by multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service.

While utilities like PSNH enjoy varying (and declining) degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free, open market for the input factors of utility service, whether labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This is just as true for capital as for any other factor of utility service. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on debt capital, or the expected return on equity.

Q. HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE CONCEPT OF OPPORTUNITY COST?

A. The concept of a fair return is intimately related to the economic concept of "opportunity cost." When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they are also exposing their funds to risk and forgoing returns from investing their money in alternative comparable risk investments. The compensation they require is the price of capital. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. These differences in risk are translated by the capital markets into price differences in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

Q. HOW DOES A REGULATED UTILITY COMPANY OBTAIN ITS CAPITAL AND HOW IS ITS OVERALL COST OF CAPITAL DETERMINED?

A. The funds employed by a utility company are generally obtained in two general forms, debt capital and common equity capital. The cost of debt funds can be ascertained easily from an examination of the contractual interest payments. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments. Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded cost of debt, based on the utility's capital structure, in order to arrive at the overall cost of capital.

Q. WHAT IS THE MARKET REQUIRED RATE OF RETURN ON EQUITY CAPITAL?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions in capital markets. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments in other companies, and the returns available from other investments of comparable risk.

II. COST OF EQUITY CAPITAL ESTIMATES

Q. DR. MORIN, WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section of my testimony is to estimate the overall cost of common equity capital for PSNH - - a vertically integrated electric utility company. In a subsequent section, I will recommend the risk premium for PSNH's generation business that must be added to this overall cost of common equity

Q. DR. MORIN, HOW DID YOU ESTIMATE THE FAIR RATE OF RETURN ON COMMON EQUITY?

A. I employed three methodologies: (1) the CAPM, (2) the Risk Premium, and (3) the DCF methodologies. All three are market-based methodologies and are designed to estimate the return required by investors on the common equity capital committed to the vertically integrated electric utility industry. Specifically, I performed two CAPM analyses, one using the standard form of the CAPM and another using an empirical approximation of the CAPM ("ECAPM"). I performed three risk premium analyses: (1) a historical risk premium analysis on the electric utility industry; (2) a historical risk premium analysis on the natural gas utility industry; and (3) a study of the risk premiums allowed in the electric utility industry. I also performed DCF analyses on three surrogates for the vertically integrated electric utility business. They are: a group of electric utilities that make up Moody's Electric Utility Index and therefore are representative of the industry, a group of investment-grade vertically integrated electric utilities, and a group of natural gas distribution utilities as proxies for the "wires" portion of the industry.

Q. WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE COST OF EQUITY?

A. No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement errors and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of capital.

Q. ARE THERE ANY DIFFICULTIES IN APPLYING COST OF CAPITAL METHODOLOGIES IN THE CURRENT ENVIRONMENT OF CHANGE?

A. Yes, there are. All the traditional cost of equity estimation methodologies are difficult to implement when you are dealing with the fast-changing circumstances of the electric utility industry. This is because electric utility company historical data have become less meaningful for an industry in a state of change. Past earnings and dividend trends are simply not indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including high energy prices, structural transformation and the transition to a more competitive environment. As a result, they are not representative of the future long-term earning power of these companies. Moreover, historical growth rates are not representative of future trends for several electric utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data are available. A similar argument applies to historical risk measures. Historical measures of risk, such as beta, are likely to be downward-biased in assessing the present industry risk circumstances.

Q. DR. MORIN, ARE YOU AWARE THAT SOME REGULATORY COMMISSIONS AND SOME ANALYSTS HAVE PLACED PRINCIPAL RELIANCE ON DCF-BASED ANALYSES TO DETERMINE THE COST OF EQUITY FOR PUBLIC UTILITIES?

A. Yes, I am.

Q. DO YOU AGREE WITH THIS APPROACH?

A. While I agree that it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. There are three broad generic methodologies available to measure the cost of equity: DCF, Risk Premium, and CAPM. All of these methodologies are accepted and used by the financial community and supported in the financial literature.

When measuring the cost of common equity, which essentially deals with the measurement of investor expectations, no one single methodology provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and apply the methodology. The failure of the traditional infinite growth DCF model to account for changes in relative market valuation, and the practical difficulties of specifying the expected growth component are vivid examples of the potential shortcomings of the DCF model. It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that these methodologies should be applied to multiple groups of comparable risk companies.

There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. Absent any hard evidence as to which method outperforms the other, all relevant evidence should be used, without discounting the value of any results, in order to minimize judgmental error, measurement error, and conceptual infirmities. I submit that a regulatory body should rely on the results of a variety of methods applied to a variety of comparable groups. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or Risk Premium result constitutes the perfect explanation of that stock price or the cost of equity.

Q. DOES THE FINANCIAL LITERATURE SUPPORT THE USE OF MORE THAN A SINGLE METHOD?

A. Yes. Authoritative financial literature strongly supports the use of multiple methods. For example, Professor Brigham, a widely respected scholar and finance academician, asserts:

> "*In practical work, it is often best to use all three methods - CAPM, bond yield plus risk premium, and DCF - and then apply judgement when the methods produce different results. People experienced in estimating capital costs recognize that both careful analysis and some very fine judgements are required. It would be nice to pretend that these judgements are unnecessary and to specify an easy, precise way of determining the exact cost of equity capital. Unfortunately, this is not possible*".[1]

[1] E. F. Brigham and L. C. Gapenski, Financial Management Theory and Practice, p. 256 (4th ed., Dryden Press, Chicago, 1985).

In a subsequent edition of his best-selling corporate finance textbook, Dr. Brigham discusses the various methods used in estimating the cost of common equity capital, and states:

> "*However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive - no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods…..*"[2]

Another prominent finance scholar, Professor Stewart Myers, in his best selling corporate finance textbook, points out:

> "*The constant growth formula and the capital asset pricing model are two different ways of getting a handle on the same problem.*"[3]

In an earlier article, Professor Myers explains:

> "*Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.*"[4]

Q. DOESN'T THE BROAD USAGE OF THE DCF METHODOLOGY IN PAST REGULATORY PROCEEDINGS INDICATE THAT IT IS SUPERIOR TO OTHER METHODS?

A. No, it does not. Uncritical acceptance of the standard DCF equation vests the model with a degree of infallibility that is not always present. One of the leading

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[2] *Id.* at p. 348.

[3] R. A. Brealey and S. C. Myers, Principles of Corporate Finance, p. 182 (3rd ed., McGraw Hill, New York, 1988).

[4] S. C. Myers, "On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment," Financial Management, p. 67 (Autumn 1978).

experts on regulation, Dr. C. Phillips discusses the dangers of relying solely on the DCF model:

> *"[U]se of the DCF model for regulatory purposes involves both theoretical and practical difficulties. The theoretical issues include the assumption of a constant retention ratio (i.e. a fixed payout ratio) and the assumption that dividends will continue to grow at a rate 'g' in perpetuity. Neither of these assumptions has any validity, particularly in recent years. Further, the investors' capitalization rate and the cost of equity capital to a utility for application to book value (i.e. an original cost rate base) are identical only when market price is equal to book value. Indeed, DCF advocates assume that if the market price of a utility's common stock exceeds its book value, the allowable rate of return on common equity is too high and should be lowered; and vice versa. Many question the assumption that market price should equal book value, believing that the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies."*

> *"...[T]here remains the circularity problem: Since regulation establishes a level of authorized earnings which, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. For all of these reasons, the DCF model 'suggests a degree of precision which is in fact not present' and leaves 'wide room for controversy about the level of k [cost of equity]'".*[5]

Sole reliance on the DCF model simply ignores the capital market evidence and investors' use of other theoretical frameworks such as the Risk Premium and CAPM methodologies. The DCF model is only one of many tools to be employed in conjunction with other methods to estimate the cost of equity. It is not a superior methodology which supplants other financial theory and market evidence.

[5] C. F. Phillips, The Regulation of Public Utilities Theory and Practice. (Public Utilities Reports, Inc., 1988) pp. 356-57. [Footnotes omitted]

Q. DO THE ASSUMPTIONS UNDERLYING THE DCF MODEL REQUIRE THAT THE MODEL BE TREATED WITH CAUTION?

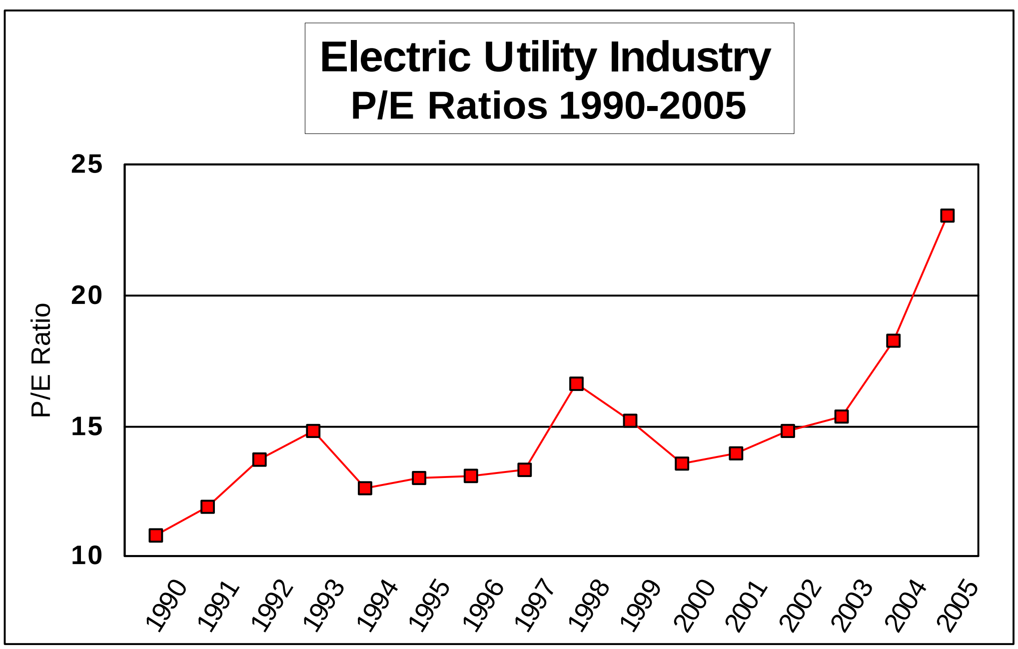
A. Yes, particularly in today's rapidly changing utility industry. Even ignoring the fundamental thesis that several methods and/or variants of such methods should be used in measuring equity costs, the DCF methodology, as those familiar with the industry and the accepted norms for estimating the cost of equity are aware, is dangerously fragile at this time.

Several fundamental and structural changes have transformed the energy utility industry since the standard DCF model and its assumptions were developed. Deregulation, increased competition triggered by national policy, accounting rule changes, changes in customer attitudes regarding utility services, the evolution of alternative energy sources, and mergers-acquisitions have all influenced stock prices in ways that deviated substantially from the early assumptions of the DCF model. These changes suggest that some of the raw assumptions underlying the standard DCF model, particularly that of constant growth and constant relative market valuation, are of questionable pertinence at this point in time for utility stocks, and that the DCF model should be complemented, at a minimum, by alternate methodologies to estimate the cost of common equity.

Q. IS THE CONSTANT RELATIVE MARKET VALUATION ASSUMPTION INHERENT IN THE DCF MODEL ALWAYS REASONABLE?

A. No, not always. Caution must also be exercised when implementing the standard DCF model in a mechanistic fashion, for it may fail to recognize changes in relative market valuations. The traditional DCF model is not equipped to deal with surges in market-to-book ("M/B") and price-earnings ("P/E") ratios. The standard DCF model assumes a constant market valuation multiple, that is, a constant P/E ratio and a constant M/B ratio. That is, the model assumes that investors expect the ratio of market price to dividends (or earnings) in any given year to be the same as the current ratio of market price to dividend (or earnings) ratio, and that the stock price will grow at the same rate as the book value. This must be true if the infinite growth assumption is made.

This assumption is somewhat unrealistic under current conditions. The DCF model is not equipped to deal with gyrations in M/B and P/E ratios, as was experienced by several utility stocks, in recent years, as illustrated in the graph below for the 1990-2005 period.



In short, caution and judgment are required in interpreting the results of the DCF model because of (1) the effect of changes in risk and growth on electric utilities, (2) the fragile applicability of the DCF model to utility stocks in the current capital market environment, and (3) the practical difficulties associated with the growth component of the DCF model. Hence, there is a clear need to go beyond the DCF results and take into account the results produced by alternate methodologies in arriving at a return on equity ("ROE") recommendation.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR RISK PREMIUM ANALYSES.

A. In order to quantify the risk premium for a vertically integrated utility such as PSNH, I have performed five risk premium studies. The first two studies deal with aggregate stock market risk premium evidence using two versions of the CAPM methodology and the other three deal directly with the energy utility industry.

II. A. CAPM ESTIMATES

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM RISK PREMIUM APPROACH.

A. My first two risk premium estimates for the vertically integrated electric utility industry are based on the CAPM and on an empirical approximation to the CAPM (ECAPM). The CAPM is a fundamental paradigm of finance. The fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + \beta(R_M - R_F)$$

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium given by $\beta(R_M - R_F)$. To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, ($R_M - R_F$). For the risk-free rate, I used a range of 4.8% - 5.4%. In order to estimate the CAPM return for the vertically integrated electric utility industry, I used a beta estimate of 0.81 and a market risk premium estimate of 7.8%. These inputs to the CAPM are explained below.

Q. HOW DID YOU DETERMINE THE RISK-FREE RATE USED IN YOUR RISK PREMIUM ANALYSES?

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return is required as a benchmark. As a proxy for the risk-free rate, I have relied on the actual yields on thirty-year Treasury bonds. Long-term rates are the relevant benchmarks when determining the cost of common equity rather than short-term or intermediate-term interest rates. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates for purposes of implementing monetary policy. For example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are used by foreign governments, companies, and individuals as a temporary safe-house for money.

As a practical matter, it is inappropriate to relate the return on common stock to the yield on short-term instruments. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors different from those influencing the yields on long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury Bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

Q. WHY DID YOU SELECT THE YIELD ON 30-YEAR TREASURY BONDS AS A PROXY FOR THE RISK-FREE RATE IN THE CAPM ANALYSIS?

A. Since common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, the yield on very long-term government bonds, namely, the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the risk premium method. The expected common stock return is based on very long-term cash flows, regardless of an individual's holding time period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments.

While long-term Treasury bonds are potentially subjected to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (pension funds, insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners.

The level of U.S. Treasury 30-year bond yields prevailing in March 2005 as reported by ValueBond on the Yahoo Finance Web site was 4.8%.

This yield, however, may not fully reflect the level of long-term bond yields in the near term. In response to the ongoing economic recovery and Federal Reserve policy, long-term yields are projected to rise substantially over the year 2005. The consensus forecast for the yield on 10-year Treasury bonds in March 2006 reported in the March 2005 edition of Consensus Forecast published by Consensus Economics Inc. is 5.1%, an increase of 60 basis points (0.60%) over its current level of level of 4.5%. The Business Week Economists Survey published in the January 3rd 2005 edition of Business Week reports a similar forecast increase in long-term interest rates. Since long-term interest rates generally move in unison, an increase (decrease) in the yield on 10-year Treasury bonds will be accompanied by a parallel increase (decrease) in the yield on 30-year bonds. Given the prevailing level of 4.8% for 30-year Treasury bonds, the implied forecast for 30-year U. S. Treasury securities is therefore a mirror increase of 60 basis points from 4.8% to 5.4%. The forecast increase in long-term yields is not surprising in view of the economic growth of the U.S. economy, declining unemployment, high federal and trade deficits, and rising core inflation. Accordingly, I shall use a range of 4.8% - 5.4% as my estimate of the risk-free rate component of the CAPM.

Q. HOW DID YOU SELECT THE BETA FOR YOUR CAPM ANALYSIS?

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as “beta”, or “systematic risk”. The beta coefficient measures change in a security’s return relative to that of the market. The beta coefficient states the extent and direction of movement in the rate of return on a stock relative to the movement in the rate of return on the market as a whole. The beta coefficient indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market, and thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation which are reflected in investors' return requirements.

Technically, the beta of a stock is a measure of the covariance of the return on the stock with the return on the market as a whole. Accordingly, it measures dispersion in a stock's return which cannot be reduced through diversification. In abstract theory for a large diversified portfolio, dispersion in the rate of return on the entire portfolio is the weighted sum of the beta coefficients of its constituent stocks.

As proxies for the vertically integrated electric utility industry, I examined the historical betas for electric utility companies contained in the current edition of the Value Line Investment Analyzer software ("VLIA"). As displayed on page 1 of Exhibit RAM-2, the average beta for the electric utility industry, as represented by the electric utilities that make up Moody's Electric Utility Index, is currently 0.82. The average beta for all the electric utilities covered by Value Line is 0.81 which is very close to previous estimate, as displayed on page 2 of Exhibit RAM-2. Based on these results, I shall use 0.81 as my beta estimate.

Q. WHAT MARKET RISK PREMIUM ESTIMATE DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the market risk premium, I used 7.8%. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums. First, the Ibbotson Associates study, *Stocks, Bonds, Bills, and Inflation, 2004 Yearbook*, compiling historical returns from 1926 to 2003, shows that a broad market sample of common stocks outperformed long-term U. S. Treasury bonds by 6.6%. The historical market risk premium over the income component of long-term Treasury bonds rather than over the total return is 7.2%. Ibbotson Associates recommend the use of the latter as a more reliable estimate of the historical market risk premium, and I concur with this viewpoint. This is because the income component of total bond return (*i.e.* the coupon rate) is a far better estimate of expected return than the total return (*i.e.* the coupon rate + capital gain), as realized capital gains/losses are largely unanticipated by bond investors.

Second, a DCF analysis applied to the aggregate equity market as of March 2005 using Value Line's aggregate stock market index and growth forecasts indicates a prospective market risk premium of 8.5%. I have used 7.8%, the average of the historical estimate (7.2%) and prospective estimate (8.5%), as a reasonable proxy for the market risk premium.

Q. WHY DID YOU USE LONG TIME PERIODS IN ARRIVING AT YOUR HISTORICAL MARKET RISK PREMIUM ESTIMATE?

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, it is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the market risk premium with historical returns. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate market risk premium minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. The best estimate of the future risk premium is the historical mean. Since I found no evidence that the market price of risk or the amount of risk in common stocks has changed over time, that is, no significant serial correlation in the Ibbotson study, it is reasonable to assume that these quantities will remain stable in the future.

Q. PLEASE DESCRIBE YOUR PROSPECTIVE APPROACH IN DERIVING THE MARKET RISK PREMIUM IN THE CAPM ANALYSIS.

A. For my prospective estimate of the market risk premium, I applied a DCF analysis to the dividend-paying stocks that make up the aggregate equity market using Value Line's VLIA software. The dividend yield on the aggregate market is currently 2.2% (VLIA 2/2005 edition), and the projected five-year dividend growth for some 1800 dividend-paying stocks covered by Value Line is 11.2%. Adding the dividend yield to the growth component produces an expected return on the aggregate equity market of 13.4%. Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate which brings this estimate to 13.7%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings this estimate to approximately 13.9%. The implied risk premium is therefore 8.5% over long-term U.S. Treasury bonds that are expected to yield 5.4%. The average of the historical (7.2%) and prospective estimate (8.5%) is 7.8%.

As a check on my market risk premium estimate, I examined a recent 2003 comprehensive article published in *Financial Management*, Harris, Marston, Mishra, and O'Brien ("HMMO") that provides estimates of the ex ante expected returns for S&P 500 companies over the period 1983-1998[6]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P

[6] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," *Financial Management*, Autumn 2003, pp. 51-66.

500 for each month from January 1983 to August 1998 by using the constant growth DCF model. The prevailing risk-free rate for each year was then subtracted from the expected rate of return for the overall market to arrive at the market risk premium for that year. The table below, drawn from HMMO Table 2, displays the average prospective risk premium estimate (Column 2) for each year from 1983 to 1998. The average market risk premium estimate for the overall period is 7.2%, which is exactly equal to the historical risk premium and reasonably close to my estimate of 7.8%.

Market Risk Premium Estimates

Year	DCF Market Risk Premium
1983	6.6%
1984	5.3%
1985	5.7%
1986	7.4%
1987	6.1%
1988	6.4%
1989	6.6%
1990	7.1%
1991	7.5%
1992	7.8%
1993	8.2%
1994	7.3%
1995	7.7%
1996	7.8%
1997	8.2%
1998	9.2%
MEAN	**7.2%**

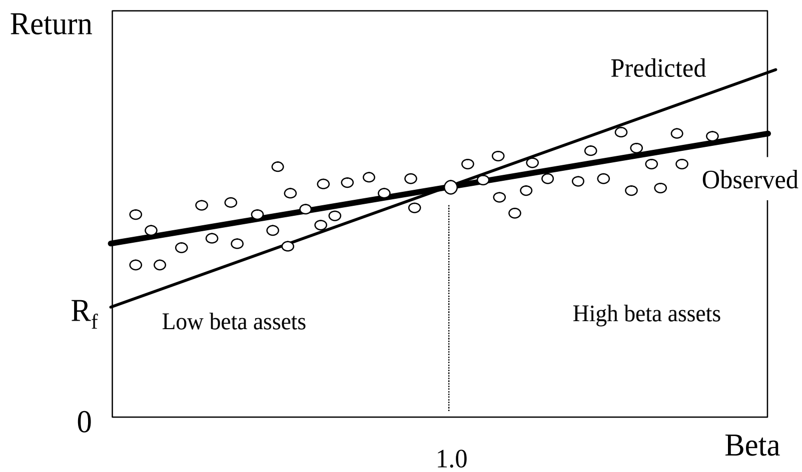
Q. WHAT IS YOUR RISK PREMIUM ESTIMATE OF THE COST OF EQUITY USING THE CAPM APPROACH?

A. Inserting those input values in the CAPM equation, namely a risk-free rate of 4.8%, a beta of 0.81, and a market risk premium of 7.8%, the CAPM estimate of the cost of common equity is: 4.8% + 0.81 x 7.8% = 11.1%. This estimate becomes 11.4% with flotation costs. The need for a flotation cost allowance is discussed at length later in my testimony. Using the forecast risk-free of 5.4%, the CAPM estimate becomes 12.0%, that is, 5.4% + 0.81 x 7.8% = 11.7%, without flotation costs and 12.0% with flotation costs.

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE USING THE EMPIRICAL VERSION OF THE CAPM?

A. It is well established in the academic finance literature that the CAPM produces a downward-biased estimate of equity cost for companies with a beta of less than 1.00. This literature is conveniently summarized in Chapter 13 of my book, Regulatory Finance, published by Public Utilities Report, Inc. Expanded CAPMs have been developed which relax some of the more restrictive assumptions underlying the traditional CAPM responsible for this bias, and thereby enrich its conceptual validity. As shown graphically below, these expanded CAPMs typically produce a risk-return relationship that is “flatter” than the traditional CAPM's prediction, consistent with the empirical findings of the finance literature. In other words, investors required higher returns for low-beta assets such as utility stocks and lower returns for high-beta assets than predicted by the plain form of the CAPM.

CAPM: Predicted vs Observed Returns



Appendix A contains a full discussion of the ECAPM, including its theoretical and empirical underpinnings.

The following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$

Inserting 4.8% for the risk-free rate R_F, a market risk premium of 7.8% for $R_M - R_F$ and a beta of 0.81 in the above equation, the return on common equity is 11.5% without flotation costs and 11.8% with flotation costs. The corresponding estimates using a risk-free rate of 5.4% are 12.1% and 12.4%.

Q. PLEASE SUMMARIZE YOUR CAPM ESTIMATES.

A. The table below summarizes the ROE estimates obtained from the CAPM studies. The average CAPM result is 11.9% without the necessary generation risk premium.

CAPM	% ROE
CAPM Risk-free rate 4.8%	11.4%
CAPM Risk-free rate 5.4%	12.0%
Empirical CAPM Risk-free rate 4.8%	11.8%
Empirical CAPM Risk-free rate 5.4%	12.4%
AVERAGE	**11.9%**

II. B. RISK PREMIUM ESTIMATES

Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE ELECTRIC UTILITY INDUSTRY.

A. An historical risk premium for the electric utility industry was estimated with an annual time series analysis applied to the electric utility industry as a whole, using Moody's Electric Utility Index as an industry proxy. The analysis is depicted on Exhibit RAM-3. The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year from 1931 to 2001 using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year.

The average risk premium over the period was 5.6% over long-term Treasury bonds. Given that long-term Treasury bonds are currently yielding 4.8%, the implied cost of equity for the average electric utility from this particular method is 4.8% + 5.6% = 10.4% without flotation costs and 10.7% with flotation costs. The need for a flotation cost allowance is discussed at length later in my testimony. Given that long-term Treasury bonds are projected to yield 5.4% in 2006, the implied cost of equity for the average electric utility is 5.4% + 5.6% = 11.0% without flotation costs and 11.3% with flotation costs.

Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE NATURAL GAS DISTRIBUTION INDUSTRY.

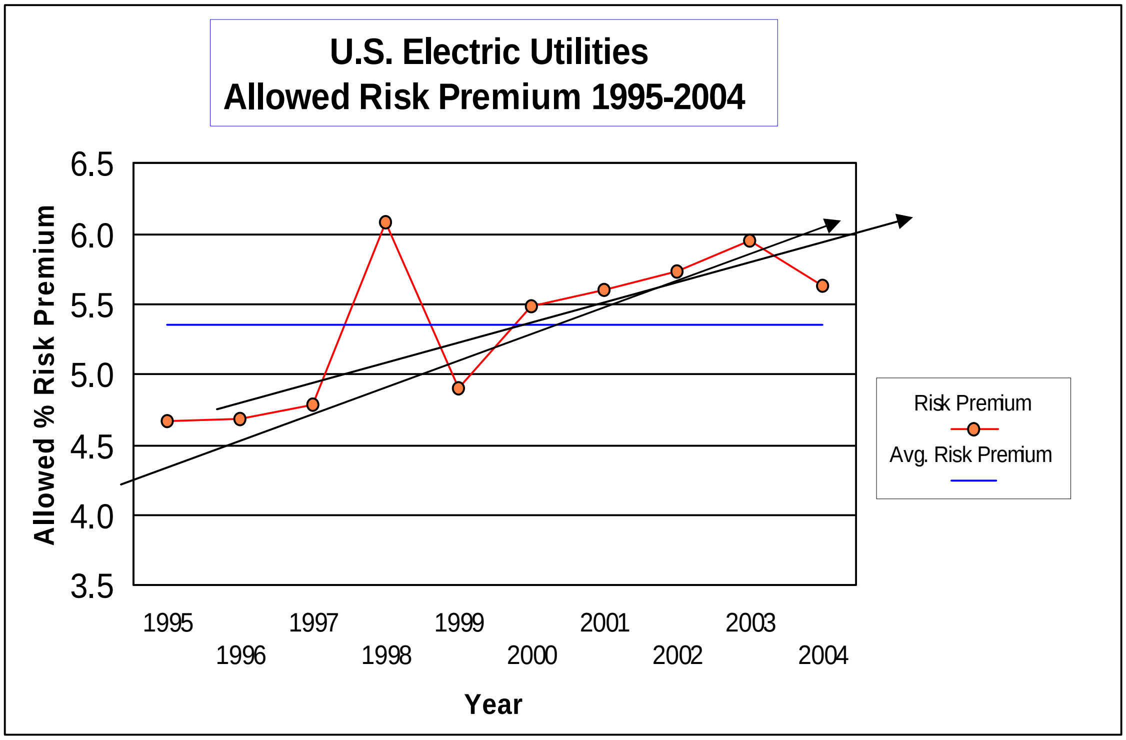
A. The same risk premium analysis was applied to the natural gas utility industry. This provides a conservative proxy for the vertically integrated electric utility industry, since gas distribution is quite similar to the electric utility industry's energy delivery business, yet lacks the added risk associated with its generation function.

A historical risk premium for the natural gas distribution utility industry was estimated with an annual time series analysis from 1955 to 2001 applied to the natural gas distribution industry as a whole, using Moody's Natural Gas Distribution Index as an industry proxy. Data for this particular index was unavailable for periods prior to 1955. The analysis is depicted on Exhibit RAM-4. The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year from 1955 to 2001, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year. The average risk premium over the period was 5.7% over long-term Treasury bonds. Given that long-term Treasury bonds are currently yielding 4.8%, the implied cost of equity for the average electric utility from this particular method is 4.8% + 5.7% = 10.5% without flotation costs and 10.8% with flotation costs. Given that long-term Treasury bonds are expected to yield 5.4% in 2006, the implied cost of equity is 5.4% + 5.7% = 11.1% without flotation costs and 11.4% with flotation costs.

II. C. ALLOWED RISK PREMIUMS

Q. PLEASE DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN THE ELECTRIC UTILITY INDUSTRY.

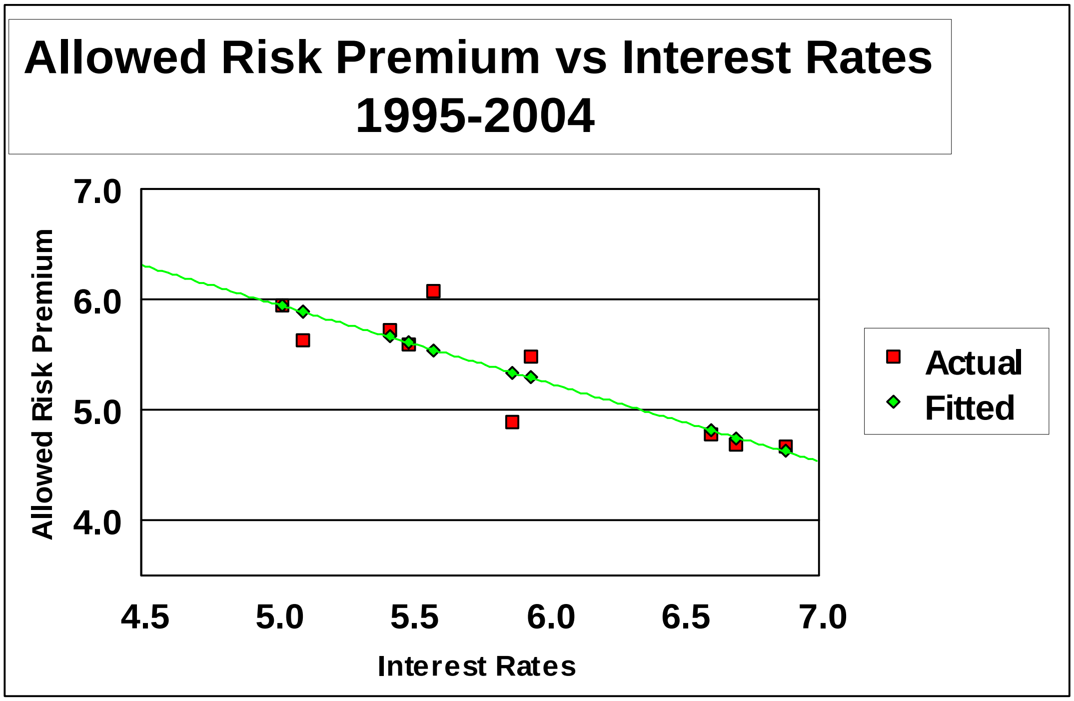
A. To estimate the Company's cost of common equity, I also examined the historical risk premiums implied in the returns on equity ("ROE") allowed by regulatory commissions over the last decade relative to the contemporaneous level of the long-term Treasury bond yield. The average ROE spread over long-term Treasury yields was 5.4% for the 1995-2004 time period, as shown by the horizontal line in the graph below. The graph also shows the year-by-year allowed risk premium. As indicated by the rising arrow on the graph, the escalating trend of the risk premium in response to lower interest rates and rising competition and restructuring is noteworthy.



A careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium ("RP") and interest rates ("YIELD") emerges over the last decade:

$$RP = 9.5177 - 0.7104\ YIELD \qquad R^2 = 0.77$$
$$(t = 5.2)$$

The relationship is highly statistically significant as indicated by the high R^2 and statistically significant t-value of the slope coefficient. The figure below shows a clear inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.



Inserting the current long-term Treasury bond yield of 4.8% in the above equation suggests that a risk premium estimate of 6.1% should be allowed for the average risk vertically integrated electric utility, implying a cost of equity of 10.9%. Using the projected bond yield of 5.4%, the risk premium is 5.7%, and the implied cost of equity is 11.1%.

Q. PLEASE SUMMARIZE YOUR RISK PREMIUM ESTIMATES.

A. The table below summarizes the ROE estimates obtained from the risk premium studies. The average risk premium result is 11.0%, without the necessary generation risk premium.

Risk Premium	% ROE
Risk Premium Electric at 4.8%	10.7%
Risk Premium Electric at 5.4%	11.3%
Risk Premium Natural Gas at 4.8%	10.8%
Risk Premium Natural Gas at 5.4%	11.4%
Allowed Risk Premium at 4.8%	10.9%
Allowed Risk Premium at 5.4%	11.1%
AVERAGE	11.0%

II. D. DCF ESTIMATES

Q. PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend at the end of the coming year

P_o = current stock price

g = expected growth rate of dividends, earnings, P_0, book value

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return, K_e, can be viewed as the sum of an expected dividend yield, D_1/P_o, plus the expected growth rate of future dividends and stock price, g. The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer "K_e" from the observed share price, the observed dividend, and from an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known, and are discussed in detail in Chapter 4 of my reference book, Regulatory Finance. The traditional DCF model requires the following main assumptions: a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The traditional DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis.

Q. HOW DID YOU ESTIMATE THE COST OF EQUITY WITH THE DCF MODEL?

A. I applied the DCF model to three proxy groups for the vertically integrated electric utility industry: the electric utilities that make up Moody's electric utilities index, a group of investment-grade vertically integrated electric utilities, and a group consisting of actively-traded dividend-paying natural gas distribution companies drawn from the Value Line Gas Distribution Group.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/P_o) and the expected long-term growth (g). The expected dividend D_1 in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the current price of the security at the time of estimating the cost of equity. The reason is that current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the dividend yields reported in the February 2005 edition of Value Line's VLIA. Basing dividend yields on average results from a large group of companies reduces the concern that idiosyncrasies of individual company stock prices will result in an unrepresentative dividend yield.

Q. HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF MODEL?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed.

As proxies for expected growth, I examined growth estimates developed by professional analysts employed by large investment brokerage institutions. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available to investors and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model. Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research Inc. (“Zacks”). I used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. I also used Value Line’s growth forecast as an additional proxy.

Q. WHY DID YOU REJECT THE USE OF HISTORICAL GROWTH RATES IN APPLYING THE DCF MODEL TO ELECTRIC UTILITIES?

A. Columns 1, 2, and 3 of Exhibit RAM-5 display the historical growth in earnings, dividends, and book value per share over the last five years for the electric utility companies that make up Value Line’s Electric Utility composite group. The average historical growth rates in earnings, dividends, and book value for the group are 1.8%, -2.5%, and 2.0% over the past 5 years, respectively. Several companies have experienced a negative earnings growth rate, as evidenced by the numerous historical growth rates reported on the table that are negative.

These historical growth rates have little relevance as proxies for future long-term growth. They are downward-biased by the sluggish earnings performance in the last five years, due to the structural transformation of the electric utility industry from a regulated monopoly to a more competitive environment. These anemic historical growth rates are certainly not representative of these companies' long-term earning power, and produce unreasonably low DCF estimates, well outside reasonable limits of probability and common sense. To illustrate, adding the historical growth rates of 1.8%, -2.5%, and 2.0% to the average dividend yield of approximately 3.4% prevailing currently produces preposterous cost of equity estimates of 5.2%, 0.9%, and 5.4%, using earnings, dividends, and book value growth rates, respectively. Of course, these estimates of equity costs are outlandish as they are less than the cost of long-term debt for these companies.

I have therefore rejected historical growth rates as proxies for expected growth in the DCF calculation. In any event, historical growth rates are somewhat redundant because such historical growth patterns are already incorporated in the analysts' growth forecasts that should be used in the DCF model.

Q. DID YOU CONSIDER DIVIDEND GROWTH PROXIES IN APPLYING THE DCF MODEL?

A. No, I did not. This is because it is widely expected that electric utilities will continue to lower their dividend payout ratio over the next several years in response to the gradual penetration of competition and its potential impact on the revenue stream. In other words, earnings and dividends are not expected to grow at the same rate in the future. According to the latest edition of Value Line, the expected dividend growth of 2.8% for the electric utility industry is far less than the expected earnings growth of 4.7% over the next few years.

Whenever the dividend payout ratio is expected to change, the intermediate growth rate in dividends cannot equal the long-term growth rate, because dividend/earnings growth must adjust to the changing payout ratio. The assumptions of constant perpetual growth and constant payout ratio are clearly not met. The implementation of the standard DCF model is of questionable relevance in this circumstance.

Dividend growth rates are unlikely to provide a meaningful guide to investors' growth expectations for electric utilities in general. This is because electric utilities' dividend policies have become increasing conservative as business risks in the industry have intensified steadily. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks. To wit, the dividend payout ratios of energy utilities has steadily decreased from about 80% ten years ago to the 60% level today. As a result, investors' attention has shifted from dividends to earnings. Therefore, earnings growth provides a more meaningful guide to investors' long-term growth expectations. After all, it is growth in earnings that will support future dividends and share prices.

Q. IS THERE ANY EMPIRICAL EVIDENCE DOCUMENTING THE IMPORTANCE OF EARNINGS IN EVALUATING INVESTORS' EXPECTATIONS IN THE INVESTMENT COMMUNITY?

A. Yes, there is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. First, the sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. To illustrate, Value Line, Zacks Investment, First Call Thompson, and Multex provide comprehensive compilations of investors' earnings forecasts, to name some. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Second, surveys of analytical techniques actually used by analysts reveal the dominance of earnings and conclude that earnings are considered far more important than dividends. Third, Value Line's principal investment rating assigned to individual stocks, Timeliness Rank, is based primarily on earnings, accounting for 65% of the ranking.

Q. DID YOU CONSIDER ANY OTHER METHOD OF ESTIMATING EXPECTED GROWTH IN THE DCF MODEL?

A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the "retention growth" method. According to this method, future growth is estimated by multiplying the fraction of earnings expected to be retained by the company, 'b', by the expected return on book equity, 'ROE':

$$g = b \times ROE$$

where: g = expected growth rate in earnings/dividends

b = expected retention ratio

ROE = expected return on book equity

I do not generally subscribe to the growth results produced by this particular method for several reasons. First, the sustainable method of predicting growth is only accurate under the assumptions that the return on book equity (ROE) is constant over time and that no new common stock is issued by the company, or if so, it is sold at book value. Second, and more importantly, the sustainable growth method contains a logical trap: the method requires an estimate of ROE to be implemented. But if the ROE input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Finally, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock price and price/earnings ratios, as analysts' growth forecasts[7]. I have therefore placed no reliance on this method.

[7] See Vander Weide and Carleton, "*Investor Growth Expectations*: *Analysts vs. History*," (*The Journal of Portfolio Management, Spring 1988); Timme & Eiseman, "On the Use of Consensus Forecasts of Growth in the Constant Growth Model: The Case of Electric Utilities,*" (Financial Management, Winter 1989).

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR MOODY'S ELECTRIC UTILITIES GROUP?

A. Exhibit RAM-6 displays the electric utilities that make up Moody's Electric Utility Index. As shown on Column 2 of page 1 of Exhibit RAM-6, the average long-term growth forecast obtained from Zacks is 4.6% for this group. Adding this growth rate to the average expected dividend yield of 4.4% shown in Column 3 produces an estimate of equity costs of 9.1% for the group, unadjusted for flotation costs. Adding an allowance for flotation costs to the results of Column 4 brings the cost of equity estimate to 9.3%, shown in Column 5.

Using Value Line's long-term earnings growth forecast instead of the Zacks consensus forecast, the cost of equity for the Moody's group is 10.8%. The analysis is displayed on Exhibit RAM-7. The original dividend yield and growth data are presented on Page 1 of Exhibit RAM-7. Companies with negative long-term growth projections, namely, ConEd, Duke Energy, Progress Energy, Public Service Enterprise Group and IDACORP, were eliminated from the group. The remaining companies are shown on Page 2 of Exhibit RAM-7, along with the DCF estimates. If the three companies whose DCF cost of equity less than the cost of debt, namely American Electric Power, CH Energy, IDACORP, are eliminated from the calculation, the cost of equity estimate is 10.8%, as displayed on Page 3 of Exhibit RAM-7. Removing the very high Duquesne Light result from the average, the average cost of equity estimate is 10.3%.

Q. PLEASE DESCRIBE YOUR SECOND PROXY GROUP FOR THE VERTICALLY INTEGRATED ELECTRIC UTILITY INDUSTRY.

A. As a second proxy for the vertically integrated electric utility industry, my second group of companies consists of investment-grade vertically integrated electric utilities covered in the Value Line Investment Survey and in Moody's Sourcebook, Power and Energy Company, October 2004. To identify the sample of vertically integrated electric utilities, I retained those electric utilities defined as "vertically integrated" electric utility operating companies by Moody's, and then matched each operating company with its publicly-traded parent company. Companies below investment-grade, that is, companies with a bond rating below Baa3, were eliminated as well as those companies without Value Line coverage. The sample of 35 companies is shown on Page 1 of Exhibit RAM-8. Three non-dividend paying companies, AES, CMS Energy and El Paso Electric, were eliminated. The three companies for which no analyst growth forecast is available from Zacks, namely CLECO, Green Mountain Power, and MGE, were eliminated as well. The resulting sample of companies on which a DCF analysis can be performed is shown on Page 2 of Exhibit RAM-8.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE VERTICALLY INTEGRATED ELECTRIC UTILITIES GROUP USING ANALYSTS' LONG-TERM GROWTH PROJECTIONS?

A. As shown on Column 2 of page 2 of Exhibit RAM-8, the average long-term analysts' growth forecast obtained from Zacks is 4.6% for this group. Combining this growth rate with the average expected dividend yield of 4.3% shown in

Column 3 produces an estimate of equity costs of 9.0% for the group, unadjusted for flotation costs. Adding an allowance for flotation costs to the results of Column 4 brings the cost of equity estimate to 9.2%, shown in Column 5.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE VERTICALLY INTEGRATED ELECTRIC UTILITIES GROUP USING VALUE LINE'S GROWTH FORECAST?

A. Using Value Line's growth forecast instead of the Zacks forecast, the cost of equity for the group is 9.9% inclusive of flotation costs. This analysis is displayed on pages 1-3 of Exhibit RAM-9. Page 1 displays the initial dividend yield and growth data for the companies. The three non-dividend paying companies (AES, CMS Energy, and El Paso Electric) were eliminated as well as CMS Energy and PNM Resources since no Value Line growth projections were available. The three companies with a negative long-term growth forecast (Ameren, Black Hills, Progress Energy) are discarded as well. The remaining set of companies is shown on Page 2 of Exhibit RAM-9. Finally, the three companies whose cost of equity estimate is less than the cost of long-term debt (American Electric Power, CLECO, and IDACORP) are eliminated from the computation, and the average ROE estimate for the remaining companies is 10.3%, as shown on Page 3 of Exhibit RAM-9. The average ROE is 9.9% if the outlying estimate of 20.7% for PG&E is truncated.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE NATURAL GAS UTILITIES?

A. For the reasons discussed previously, I view gas distribution utilities as a conservative proxy group for the vertically integrated electric utility industry. Accordingly, I have examined the expected returns of dividend-paying natural gas distribution utilities contained in Value Line's natural gas distribution universe with a market value in excess of $500 million. The group is shown in Exhibit RAM-10. As shown on Column 3 of Exhibit RAM-10, the average long-term growth forecast obtained from the Zacks corporate earnings database is 5.1% for the gas distribution group. Combining this growth rate with the average expected dividend yield of 3.9% shown in Column 4 produces an estimate of equity costs of 9.0% for the gas distribution group. Recognition of flotation costs brings the cost of equity estimate to 9.2%, shown in Column 6.

Repeating the exact same procedure, only this time using Value Line's long-term earnings growth forecast of 5.9% instead of the Zacks consensus growth forecast, the cost of equity for gas distribution group is 10.0%, unadjusted for flotation costs. Adding an allowance for flotation costs brings the cost of equity estimate to 10.2%. This analysis is displayed on Exhibit RAM-11.

Q. PLEASE SUMMARIZE YOUR DCF ESTIMATES.

A. The table below summarizes the DCF estimates for the various proxy groups:

DCF Study	ROE
Moody's Electrics Zacks Growth	9.3%
Moody's Electrics Value Line Growth	10.3%
Vertically Integrated Electrics Zacks Growth	9.2%
Vertically Integrated Electrics Value Line Growth	9.9%

Natural Gas Distribution Zacks Growth	9.2%
Natural Gas Distribution Value Line Growth	10.2%
AVERAGE	**9.7%**

II.E FLOTATION COSTS

Q. PLEASE DESCRIBE THE NEED FOR A FLOTATION COST ALLOWANCE.

A. All the market-based estimates reported above include an adjustment for flotation costs. The simple fact of the matter is that common equity capital is not free. Flotation costs associated with stock issues are exactly like the flotation costs associated with bonds and preferred stocks. Flotation costs are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is done routinely for bond and preferred stock issues by most regulatory commissions, including FERC. Clearly, the common equity capital accumulated by the Company is not cost-free. The flotation cost allowance to the cost of common equity capital is discussed and applied in most corporate finance textbooks; it is unreasonable to ignore the need for such an adjustment.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, *etc.*). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Appendix B to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the Company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation cost requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the Company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.52%.

According to the empirical finance literature discussed in Appendix B, total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 30 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 5.0% for utility stocks by 0.95 yields 5.3%, which is 30 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the Company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

There are several sources of equity capital available to a firm, including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plan, employees' savings plan, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

Q. IS A FLOTATION COST ADJUSTMENT REQUIRED FOR AN OPERATING SUBSIDIARY LIKE PSNH THAT DOES NOT TRADE PUBLICLY?

A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its parent, in this case, Northeast Utilities ("NU"). This objection is unfounded since the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual shareholders are absolved from such dilution. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

II.F COST OF EQUITY SUMMARY

Q. PLEASE SUMMARIZE YOUR COST OF EQUITY RESULTS FOR THE VERTICALLY INTEGRATED ELECTRIC UTILITY INDUSTRY.

A. To estimate the cost of common equity capital for the vertically integrated electric utility industry, I performed five risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other three risk premium analyses were performed on aggregate historical and allowed risk premium data from the electric utility and natural gas distribution industries. I also performed DCF analyses on three surrogates for the vertically integrated electric utility industry: a group of electric utility companies that make up Moody's Electric Utility Index, a group consisting of investment-grade vertically-integrated electric utilities, and a group of investment-grade dividend-paying natural gas distribution utilities. The results are summarized in the table below:

STUDY	ROE
CAPM Risk-free rate 4.8%	11.4%
CAPM Risk-free rate 5.4%	12.0%
Empirical CAPM Risk-free rate 4.8%	11.8%
Empirical CAPM Risk-free rate 5.4%	12.4%
Risk Premium Electric at 4.8%	10.7%

Risk Premium Electric at 5.4%	11.3%
Risk Premium Natural Gas at 4.8%	10.8%
Risk Premium Natural Gas at 5.4%	11.4%
Allowed Risk Premium at 4.8%	10.9%
Allowed Risk Premium at 5.4%	11.1%
Moody's Electrics Zacks Growth	9.3%
Moody's Electrics Value Line Growth	10.3%
Vertically Integrated Electrics Zacks Growth	9.2%
Vertically Integrated Electrics Value Line Growth	9.9%
Natural Gas Distribution Zacks Growth	9.2%
Natural Gas Distribution Value Line Growth	10.2%

The results range from a low of 9.2% to a high of 12.4% with a midpoint of 10.8%. The mean result is 10.7% and the truncated mean[8] is also 10.7%. The median result is 10.9%. If we place slightly less weight to the DCF results, the central result is 11.0%.

This result is corroborated by recent anecdotal indicators. For example, the electric industry average return on equity for the last quarter of 2004 as compiled by Regulatory Research Associates is 11.07%. Similarly, Lehman Brothers indicated that a return on equity of 11.0% was its reasonable forecast for PSNH.

Q. DO THE DCF RESULTS UNDERSTATE THE COST OF EQUITY?

A. Yes, they do. Application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the Market-to-Book (M/B) ratio is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the M/B ratio of a

[8] The truncated mean is obtained by removing the high and low estimates and averaging the remaining results.

given stock exceeds unity. This is particularly relevant in the current capital market environment where electric utility stocks are trading at M/B ratios well above unity and have been for two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.

Q. CAN YOU ILLUSTRATE THE EFFECT OF THE MARKET-TO-BOOK RATIO ON THE DCF MODEL BY MEANS OF A SIMPLE EXAMPLE?

A. Yes. The simple numerical illustration shown in the table below demonstrates the result of applying a market value cost rate to book value rate base under three different M/B scenarios. The three columns correspond to three M/B situations: the stock trades below, equal to, and above book value, respectively. The last situation (shaded portion of the table) is noteworthy and representative of the current capital market environment. The DCF cost rate of 10%, made up of a 5% dividend yield and a 5% growth rate, is applied to the book value rate base of $50 to produce $5.00 of earnings. Of the $5.00 of earnings, the full $5.00 are required for dividends to produce a dividend yield of 5% on a stock price of $100.00, and no dollars are available for growth. The investor's return is therefore only 5% versus his required return of 10%. A DCF cost rate of 10%, which implies $10.00 of earnings, translates to only $5.00 of earnings on book value, a 5% return.

The situation is reversed in the first column when the stock trades below book value. The $5.00 of earnings are more than enough to satisfy the investor's dividend requirements of $1.25, leaving $3.75 for growth, for a total return of 20%. This is because the DCF cost rate is applied to a book value rate base well above the market price.

Therefore, the DCF cost rate understates the investor's required return when stock prices are well above book, as is the case presently, and understate the cost of common equity capital.

EFFECT OF MARKET-TO-BOOK RATIO ON MARKET RETURN

		Situation 1	***Situation 2***	***Situation 3***
1	Initial purchase price	$25.00	$50.00	$100.00
2	Initial book value	$50.00	$50.00	$50.00
3	**Initial M/B**	**0.50**	**1.00**	**2.00**
4	**DCF Return 10% = 5% + 5%**	**10.00%**	**10.00%**	**10.00%**
5	Dollar Return	$5.00	$5.00	$5.00
6	Dollar Dividends 5% Yield	$1.25	$2.50	$5.00
7	Dollar Growth 5% Growth	$3.75	$2.50	$0.00
8	**Market Return**	**20.00%**	**10.00%**	**5.00%**

Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING THE VERTICALLY INTEGRATED ELECTRIC UTILITY INDUSTRY'S COST OF COMMON EQUITY CAPITAL?

A. Based on the results of all my analyses and the application of my professional judgment, it is my opinion that an overall just and reasonable return on common equity for a vertically integrated electric utility such as PSNH is 11.0%.

Q. MUST THIS OVERALL RESULT BE ADJUSTED TO ACCOUNT FOR THE FACT THAT THE POWER GENERATION SEGMENT OF THE UTILITY BUSINESS IS SUBSTANTIALLY RISKIER THAN THE OTHER SEGMENTS OF THE ELECTRIC UTILITY INDUSTRY?

A. Yes. All the cost of equity estimates derived above reflect the overall risk of the vertically integrated electric utility industry and not the higher risks associated with the power generation segment of the business. Because the latter is riskier than the remaining segments of the vertically integrated electric utility industry, the expected equity return for the generation segment must be adjusted upward. I estimate the additional risk premium attributable to the generation segment to be on the order of 40 basis points. The basis for this adjustment is fully discussed in the next section. I have therefore increased my cost of common equity recommendation of 11.0% for PSNH's overall vertically integrated electric utility operations to 11.4% in order to account for the higher relative risks of the power generation business.

III. RISK-RETURN DIFFERENTIAL

Q. DR. MORIN, WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section is to appraise the difference in risk and return between the T&D business and the power generation business.

Q. HOW DOES THE COMPANY'S POWER GENERATION SEGMENT'S COST OF CAPITAL RELATE TO THAT OF PSNH AND THAT OF ITS PARENT COMPANY, NORTHEAST UTILITIES ("NU")?

A. I am treating PSNH's power generation business as a separate stand-alone entity, distinct from PSNH and its parent company NU because it is the cost of capital for PSNH's power generation assets that we are attempting to measure in this proceeding and not the cost of capital for PSNH or NU's consolidated overall activities. Financial theory clearly establishes that the cost of equity is the risk-adjusted opportunity cost to the investor, in this case, PSNH. The true cost of capital depends on the use to which the capital is put, in this case PSNH's power generation operations in the State of New Hampshire. The specific source of funding an investment and the cost of funds to the investor are irrelevant considerations.

For example, if an individual investor borrows money at the bank at an after-tax cost of 8% and invests the funds in a speculative oil extraction venture, the required return on the investment is not the 8% cost but rather the return foregone in speculative projects of similar risk, say 20%. Similarly, the required return on PSNH's power generation assets is the return foregone in comparable risk power production operations, and is unrelated to the parent's cost of capital. The cost of capital is governed by the risk to which the capital is exposed and not by the source of funds. The identity of the shareholders has no bearing on the cost of equity.

Just as individual investors require different returns from different assets in managing their personal affairs, corporations should behave in the same manner. A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between subsidiaries. Therefore, the cost of investing funds in a business segment such as PSNH's power generation business is the return foregone on investments of similar risk and is unrelated to the identity of the investor.

Q. PLEASE EXPLAIN WHY THE BUSINESS RISKS FACED BY POWER GENERATION HAVE INCREASED IN RECENT YEARS RELATIVE TO THOSE OF THE T&D BUSINESS.

A. The business risks faced by the power generation business have certainly intensified relative to the risks of the T&D business. The industry has moved in the direction of more intense competition on the power generation side of the business; powerful buyers with many energy alternatives, including large industrial customers, result in a highly competitive market for electricity.

The state of competition in an industry depends on four basic competitive forces:

- the threat of new entrants
- the degree of rivalry among existing firms
- the threat of substitute products
- the bargaining power of customers

In recent years, all four forces have moved in the direction of more intense competition on the power generation side of the business. First, entry barriers have eroded. The traditional role of electric utilities has changed and continues to change drastically due to growing competition in the power generation industry and governmental and judicial actions. Competition has emerged in that business as regulatory barriers have been removed, for example unbundled facility elements and equal access to transmission networks. Regulatory policy has encouraged a competitive bulk wholesale power market by requiring utilities to provide wheeling and connection services.

Second, the number of new entrants and/or the intensity of competition between existing market participants have increased. Sweeping regulatory reforms have stimulated competitive forces and attracted new participants in the energy production markets. For example, non-utility generators (NUGs), self-generators, independent power producers (IPPs), and exempt wholesale generators (EWGs) have proliferated, ending the era of the vertically integrated monopoly utility for the generation component of the electric utility business.

Third, the number of substitute products and competing alternatives (electricity, gas, oil, etc.) intensifies risk. Competition in the power generation business is intense, and customers have alternative means of supplying their energy needs. Electric utilities face increasing competition from alternative energy sources in some of their important markets, especially in the large industrial users' market. Major policy changes promote the availability of substitutes and the development of competition: wheeling, expanded interconnection, and service unbundling. The unbundling of rates facilitates competitive entry and the introduction of substitutes. Not only does an industrial customer face an array of energy substitutes but also confronts a full array of electricity supply choices: investor-owned utilities, municipal utilities, NUGs, demand-side management providers, self-generation, fuel cells, and photovoltaics.

Lastly, the bargaining power of customers is increasing, particularly that of cost-conscious industrial-commercial users with viable least-cost alternatives. Large industrial customers are prime targets for new cream-skimming competitors, to the extent that rates are not reflective of costs.

In short, disintegrating entry barriers, intensifying rivalry among the rising number of competitors, more substitute products, and powerful buyers with many energy alternatives result in a highly competitive energy production market. Compounding the business risks of the power generation business are record-high and volatile fuel prices and potentially burdensome environmental compliance requirements.

Q. DOES THE INVESTMENT COMMUNITY BELIEVE THAT THE POWER GENERATION BUSINESS HAS HIGHER INVESTMENT RISKS THAN THE T&D BUSINESS?

A. Yes, it certainly does. In numerous articles discussing bond rating methods for electric companies, bond rating agencies have confirmed the view that fully-integrated electric operations which include generation are expected to exhibit higher risk profiles than transmission and distribution operations alone. To wit, the bond rating agencies have taken concrete steps to recognize the higher investment risks of the power generation business. Both Moody's and Standard and Poor's ("S&P") report that fully integrated companies are expected to be capitalized with less leverage (less debt and more equity) than electric distribution operations in recognition of the lower business risks of the latter.

In a September 1998 article discussing bond rating methods for electric companies, Standard and Poor's confirms the view that fully-integrated electric operations are expected to exhibit higher risk profiles than transmission and distribution operations:

> *Owing to the relatively low business risk of large transmission systems and regulated distribution systems (the "wires" business), business profile assessments in this area should fall within the 1-4 [low risk] range. The generation business is the most risky, reflecting the competitive nature of this business, and generators generally receive business profile [risk] assessments in the mid- to lower-end of the range....*
> *Transmission and distribution operations are typically low risk relative to generation operations... .*
>
> *Competitive pressures in the transmission and distribution businesses are generally quite limited by virtue of franchise monopolies. While introducing competition into the generation business and creating national or international power exchange systems is increasingly popular worldwide, there is near unanimous agreement that transmission and distribution systems should largely remain monopolies….* (Standard & Poor's Infrastructure Finance, "Rating Methodology for Global Power Utilities, September 1998, pp. 61-68).

In October 1999, Standard and Poor's published an updated version of the report cited above and reiterated its position regarding generation investment risks.[9] Standard and Poor's remains firm in the view that fully-integrated electric operations are expected to exhibit higher risk profiles than transmission and distribution operations.

Another major bond rating agency, Moody's Investors Service, while cautioning its subscribers that electric distribution companies' credit profiles will

[9] Standard & Poor's Infrastructure Finance, "Rating Methodology for Global Power Utilities, October 1999, pp. 131-144

vary depending on the circumstances of each company, also recognizes as a general matter that fully integrated electric utilities will have higher risk profiles than transmission and distribution operations.

> *Discussions of the looming disaggregation of the US electric utility market usually assume that the future distribution companies will be regulated, thus embodying low business risk. A secondary assumption is that they will therefore be able to tolerate quite a bit more debt than a traditional vertically-integrated utility within the same rating category. While the US is only beginning to experience any legal disaggregation of its vertically-integrated utilities, a trend which has a very long way to go in the transformation, other countries have completed the legal disaggregation of their distribution, transmission and generation businesses. Our experience rating distributors in other countries and in other energy sectors indicates that those assumptions are substantially correct….*
> *• In general, distribution companies, regardless of their business profiles, exhibit lower business risks that generation companies as they are less asset-intensive and will remain regulated to a degree.*
> *• "Pure" largely regulated distribution companies—that is, those with virtually no exposure to generation or other highly competitive and volatile energy-related businesses—can tolerate significantly lower interest or fixed charge coverage and higher leverage ratios than traditional US investor-owned utilities (IOUs) and still achieve the same rating.* (Moody's Investors Service, Global Credit Research, Special Comment, "Future Electric Distributors: More Stable than Generators, But Not Risk Free," October 1997).

Another major bond rating agency, Duff & Phelps, supports the notion that generation operations are expected to carry higher investment risk than T&D operations:

> *In general, it is reasonable to expect that within a given rating category companies involved in only the distribution and transmission segments of the electric utility business will have a lower business risk profile. This includes more stable cash flows, lower quantitative protection measures and a higher level of debt capacity than companies involved in only generation (or even in all three segments) where business risk and cash flow volatility*

> *will be higher*. (Duff & Phelps, "Special Report, the Electric Utility Industry, Credit Quality Implications of Electric Industry Disaggregation," October 1996, p. 2).

Q. CAN YOU DESCRIBE SOME OF THE FACTORS WHICH INCREASE THE BUSINESS RISK OF PSNH'S POWER GENERATION SEGMENT?

A. Yes. Many of the factors which increase the riskiness of the generation segment of the electric utility business are common throughout the industry; others are specific to the particular company such as PSNH.

Examples of risk factors common to the industry are increasingly stringent environmental and siting restrictions, volatile fuel supply and transportation costs, the ever-present concern regarding a regulatory finding of imprudent costs or operations, and the more recent concern regarding the creation and recovery of potentially stranded costs.

In addition to the common risk factors noted above, PSNH faces additional, specific factors which increase its generation business risk in the eyes of the investment community. For example, the intense New Hampshire legislative oversight of PSNH has created uncertainty and volatility concerning PSNH's generation business. The legislature has in a short period of time changed the law concerning ownership of PSNH's generating assets 180°, and in less than 10 years has enacted nearly 20 different bills impacting PSNH's specifically or the utility industry in general. PSNH's ability to operate its generation assets is subject to stringent oversight, as evidenced by the recent regulatory, judicial, and local proceedings necessary to obtain approval to convert one of the Schiller generating units to burn wood. The Schiller project approval also includes a risk/reward cost recovery formula which creates uncertainty from the vantage of the investment community. PSNH is also undergoing re-licensing of FERC hydroelectric generating projects. As part of that re-licensing process, state environmental regulators have demanded significant operational changes which would negatively impact the output of the hydroelectric stations, as well as reserving the right to mandate construction of fish passage facilities and other operational changes to accommodate endangered species. The investment community views all of these factors as contributing to the risk of PSNH's generation business.

Q. DOES THE INVESTMENT COMMUNITY VIEW THE EXISTENCE OF THE RECONCILING COST RECOVERY MECHANISM USED FOR PSNH'S GENERATION BUSINESS AS MITIGATING THESE RISKS?

A. Not to any material extent. I understand that presently PSNH has a reconciling charge that recovers the costs of its generation business. However, the volatility of the legislative process in New Hampshire, as well as ever-present environmental and prudence risks are of much greater significance to the investment community. With respect to environmental risk, the potential exists for an asset to be rendered uneconomic and therefore stranded as a result of environmental laws or regulations. Investors recognize this risk as one of the factors that is unique to generation, as it does not exist to any great extent in the delivery segment of the business.

Q. HAVE THE BOND RATING AGENCIES TAKEN CONCRETE STEPS TO RECOGNIZE THE HIGHER INVESTMENT RISKS OF THE POWER GENERATION BUSINESS?

A. Yes, they have. Both Moody's and Standard and Poor's ("S&P") report that fully integrated companies are expected to be capitalized with less leverage (less debt and more equity) than electric distribution operations in recognition of the lower business risks of the latter. For example, S&P reports in the aforementioned article regarding bond rating methodology for power companies worldwide that the median debt-to-capital ratio projected for "A" and "BBB"-rated electricity generators ranges from 35% to 45%. Whereas for transmission and distribution operations, S&P projects median debt-to-capital ratios of 55% and 65% for "A" and "BBB"-rated companies, respectively. The following table was taken in part from the article which details S & P's financial medians:

Table 1.

	Total debt to Total Capital (%)	
	A	BBB
Transmission and Distribution Cos.	55	65
Generators	35	45
Vertically Integrated Cos.	45	56

The data in the table demonstrates that "A"-rated T&D companies have a projected median debt-to-total capital ratio of about 55% (which implies a total equity ratio of 45%). This capitalization ratio is much more highly leveraged than the level S&P projects for "A"-rated generators (65% equity, 35% debt). A similar trend applies to "BBB-rated" companies.

In a more recent 2004 comprehensive study of the business risks of the utility industry, Standard & Poor's (S&P) assigned new business risk scores to U.S. utility and power companies to better reflect the relative business risk among companies in the sector. S&P has segmented the utility and power industry into the following sub-sectors reflective of their relative business risk:

1. Transmission and Distribution – Water, Gas, and Electric
2. Transmission Only – Electric, Gas, and Other
3. Integrated Electric, Gas, and Combination Utilities
4. Diversified Energy and Diversified Non-Energy
5. Energy Merchant/Developers/Trading and Marketing

Business risk scores are assigned on a 10-point scale (1 indicating low risk and 10 indicating high risk) based on the divergence of business risk. For example, the utility companies in the Transmission and Distribution category, without generation activities, have an average business risk score of 2.9, while the utility companies in the Integrated category, which includes power generation activities, have an average business score of 5.1. Similarly, companies in the Diversified category which presumably include a stronger power generation component, have an average business score of 7.7. A similar pattern applies to bond ratings. As the power generation component of a utility's activities gains in importance, the credit score declines.

III. A. THEORETICAL BACKGROUND

Q. WHAT FUNDAMENTAL CONCEPTS UNDERLIE THE DETERMINATION OF THE COST OF CAPITAL OF A BUSINESS SEGMENT?

A. Risk-averse investors require higher returns from higher risk investments. This implies that the expected return, or cost of capital, for a higher risk investment exceeds that of a lower risk investment. Viewing each unbundled business of a vertically integrated electric utility (generation, T&D) on a stand-alone basis just like any other corporate investment, the higher the risk of that business, the higher the expected return. In theory, the latter can be calculated for each individual business segment as long as reliable and relevant market and historical information are available on each entity and/or on comparable risk investments which are publicly-traded.

Q. WHAT METHODOLOGIES ARE AVAILABLE TO DETERMINE THE COST OF EQUITY OF A BUSINESS SEGMENT?

A. There are three principal methodologies to determine the cost of equity for a business segment, such as the generation component of a vertically integrated electric utility, that are empirically tractable: Pure-Play, Residual Beta, and Multiple Regression.

Q. PLEASE DESCRIBE THE PURE-PLAY APPROACH.

A. Under the Pure-Play approach, publicly-traded companies which are most similar to the business segment in question are identified. The betas of these companies can then be employed as proxies for the betas of those segments. For example, a pure-play electric distribution business would have a risk profile similar to today's natural gas distribution business. The betas of natural gas distribution utilities can therefore be used as proxies for the unobservable beta of the wires business and used in the CAPM to infer the cost of capital for that business.

Q. PLEASE DESCRIBE THE RESIDUAL BETA APPROACH TO DETERMINING THE COST OF EQUITY OF A BUSINESS SEGMENT

A. The CAPM framework provides another methodology for determining a business segment's cost of capital. A parent company can be viewed as a portfolio of assets or business segments. In the absence of significant synergy, the risk of the parent's common stock, as measured by beta, is a weighted average of the risks (betas) associated with the risk of each of its business segments. A parent company's risk is the sum of the risks of its components, that is, a parent's beta (β_p) is equal to the weighted average of the betas of its business segments, say business segments 1, 2, and 3.

$$\beta_P = w_1\beta_1 + w_2\beta_2 + w_3\beta_3 \qquad (5)$$

where, w_1, w_2 and w_3 represent the weight of the three business segments, and β_1, β_2 and β_3 the betas of those business segments. For the weights applicable to the business segments, the average percentage contribution of each business segment to assets or consolidated operating income can be used. Given that the weighted betas of all of the parent's business segments must add up to the parent's aggregate beta in the absence of synergies, and given the weighted betas of two of the three business segments, the residual beta applicable to the remaining business segment can be calculated. The CAPM formula can be used to measure the cost of equity of the "residual" business segment.

One practical difficulty with this approach is that the method presumes that if a company has 'n' business segments, the risks and relative weights of all business segments but one must be known, that is, market data must be available on 'n-1' business segments. Otherwise, the method is unusable.

Q. PLEASE DESCRIBE THE MULTIPLE REGRESSION APPROACH TO DETERMINING THE COST OF EQUITY OF A BUSINESS SEGMENT.

A. Given that the risk of a multi-business segment company is a weighted average of the risks of each of its business segments, a multi-business segment company's beta (β) equals the weighted average of the betas of its business segments. For example, for a two-business segment firm:

$$\beta = w_1\beta_1 + w_2\beta_2 \qquad (6)$$

If we consider two multi-business segment companies, A and B, each with two lines of business, then for each company:

$$\beta_A = w_1\beta_1 + w_2\beta_2 \qquad (7)$$

$$\beta_B = w_1\beta_1 + w_2\beta_2 \qquad (8)$$

The above two equations with two unknowns can be solved for the betas, β_1 and β_2. In other words, if you have data on two companies, each with two lines of business, and you know the two companies' betas as well as the weights of the two lines of business, the above two equations can easily be solved for β_1 and β_2.

More generally, if there are more companies than lines of business, the business segment betas can be estimated by running a multiple regression of the multi-business segment company betas against the line of business weights. The estimated regression coefficients become the business segment betas. The CAPM can be used to measure the business segments' cost of equity.

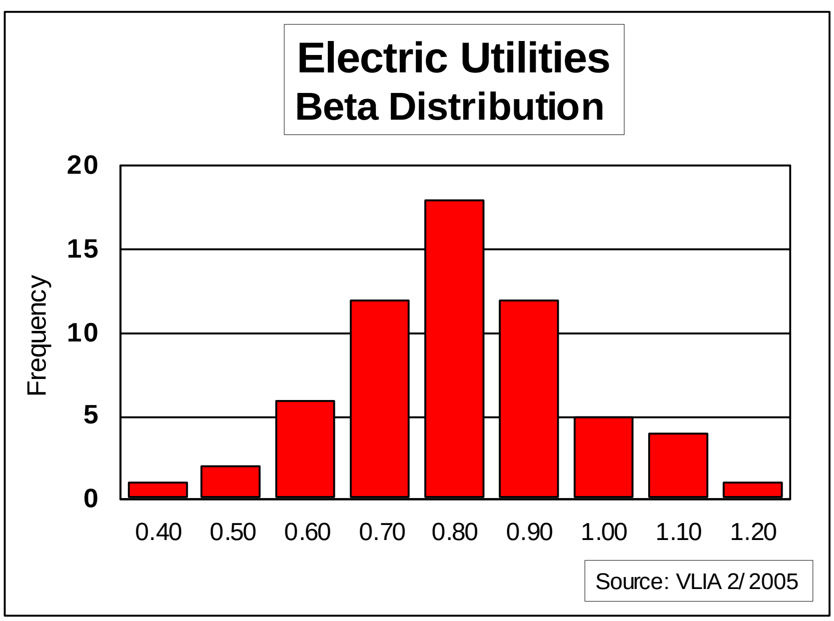
Unfortunately, this technique cannot be applied to the electric utility industry because of insufficient variability in the risk data to determine statistically meaningful estimates of risk differentials.

III. B. EMPIRICAL ESTIMATES

III.B.1 - Electric Utility Industry Betas

Q. DR. MORIN, CAN YOU PROVIDE AN OVERVIEW OF ELECTRIC UTILITY BETAS?

A. Yes, I can. Exhibit RAM-2, page 2 provides the frequency distribution of historical betas for the electric utility industry, as reported by Value Line in the February 2005 edition of the VLIA. The chart below shows the distribution of betas.



The mean, median, and truncated mean betas are all 0.80, with a standard deviation of 0.18. Given the latter standard deviation, the majority of electric utility betas therefore range from approximately 0.62 to 0.98. By virtue of their regulated natural monopoly status, it stands to reason that T&D intensive electric utilities would have betas near the lower end of the beta distribution at approximately 0.75 (third decile of the frequency distribution) and that the generation-intensive electric utilities would have betas near the upper end of the distribution at approximately 0.85 (seventh decile of the frequency distribution). It stands to reason, therefore, that the difference in beta between the two groups is 0.10, that is, 0.85 minus 0.75. This difference in risk is further corroborated by the Pure-Play results below.

<u>III.B.2 - Pure-Play Approach</u>

Q. HOW DID YOU IMPLEMENT THE PURE-PLAY APPROACH?

A. In order to estimate the difference in risk between the T&D and generation segments, I relied on the Pure-Play approach. To implement this approach, I examined the beta risk measures for companies which are reasonable surrogates for those segments. For the T&D business segment, I examined two proxies: a group of utilities designated as “distribution utilities” by Standard & Poor’s (S&P) and a group of publicly-traded natural gas utilities. For the generation segment, I examined two proxies: a group of utilities designated as “diversified utilities” by S&P and a group of oil and gas producers. I have also used the residual beta approach to estimate the beta of the power generation business.

III.B.3 - Wires Business Proxies

Q. WHAT RESULTS DID YOU OBTAIN FOR YOUR FIRST GROUP OF PROXY COMPANIES FOR THE WIRES BUSINESS?

A. As a first proxy for the wires business, I examined a large group of operating utilities designated as "distribution" utilities by S&P in a recent comprehensive analysis of utility business risks. This group, displayed on Pages 1 and 2 of Exhibit RAM-12, includes electric, gas, and water companies engaged in the predominantly monopolistic distribution business. I then identified the parent company of these operating utility companies as shown on the last column of Pages 1 and 2 of Exhibit RAM-12. The final sample consisted of those 47 parent companies that are publicly-traded with Value Line coverage and for which beta risk measures are available, as shown on Page 3 of Exhibit RAM-12. The median beta for the distribution utilities group is 0.75.

Q. WHAT RESULTS DID YOU OBTAIN FOR YOUR SECOND GROUP OF PROXY COMPANIES FOR THE WIRES BUSINESS?

A. For the second proxy group of companies for the wires business, I examined the betas of a sample of publicly-traded natural gas distribution utilities contained in the VLIA software. It is reasonable to postulate that the wires business possesses an investment risk profile similar to today's natural gas utility business. Natural gas utility companies possess economic characteristics similar to those of electric utilities. They both are involved in the transmission-distribution of energy services products at regulated rates in a cyclical and weather-sensitive market.

They both employ a capital-intensive network with similar physical characteristics. They both are subject to rate of return regulation.

In order to minimize the well-known thin trading bias in measuring beta due to non-synchronous trading, only those companies whose market capitalization exceeded $500 million were considered. The average beta for the natural gas distribution group is 0.75 as shown on Exhibit RAM-13, the same estimate as the S&P distribution utilities group.

Q. WHAT DO YOU CONCLUDE FROM THESE TWO ESTIMATES?

A. I conclude from these two proxy groups and from the industry beta frequency distribution that a reasonable beta estimate for the wires business industry is 0.75.

III.B.4 - Generation Business Proxies

Q. WHAT RESULTS DID YOU OBTAIN FOR YOUR FIRST GROUP OF PROXY COMPANIES FOR THE POWER GENERATION BUSINESS?

A. As a first proxy for the generation business, I examined a large group of operating utilities designated as “diversified energy and non-energy” utilities by S&P in a recent comprehensive analysis of utility business risks. This group, displayed on Page 1 of Exhibit RAM-14, includes principally electric utilities engaged in a diversified mix of energy utility businesses, especially power generation. I then identified the parent company of these operating utility companies as shown on the last column of Page 1 of Exhibit RAM-14. The final sample consisted of those 47 parent companies that are publicly-traded with Value Line coverage and for which beta risk measures are available, as shown on Page 2 of Exhibit RAM-

14. The median beta for the distribution utilities group is 0.85. If we confine the sample to electric utilities only, the median beta remains 0.85, as shown on Page 3 of Exhibit RAM-14.

Q. WHAT RESULTS DID YOU OBTAIN FOR YOUR SECOND GROUP OF PROXY COMPANIES FOR THE WIRES BUSINESS?

A. As a second proxy for the power generation business, I examined the betas of high-quality oil and gas producers contained in Value Line's "Petroleum Producing" universe with a Safety Rank of at least 3 and a Financial Strength Rating of at least B. As was the case earlier with the natural gas distribution group, only those companies whose market capitalization exceeded $500 million were considered in order to minimize the thin trading bias in measuring beta. The group is shown in Exhibit RAM-15. The average beta for the group is 0.85, the same estimate as the S&P diversified energy group.

III.B.5 - RESIDUAL BETA PROXY

Q. HOW DID YOU IMPLEMENT THE RESIDUAL BETA APPROACH TO DETERMINE A BETA FOR THE POWER GENERATION BUSINESS?

A. In order to estimate a beta for generation business, I applied the residual beta methodology. A vertically integrated operation can be viewed as a portfolio of businesses. In the absence of significant synergy, the risk of a vertically integrated electric utility industry's common stock, as measured by beta, is a weighted average of the risks (betas) associated with the riskiness of each of its individual businesses. Therefore, the aggregate beta (β_{vert}) of a vertically integrated utility must be equal to the weighted average beta of its wires and its generation businesses:

$$\beta_{vert} = w_w\beta_w + w_g\,\beta_g$$

where, w_w and w_g represent the weights of the wires and generation segments, and β_w and β_g represent the betas of the wires and generation segments.

Inserting the β_{vert} of 0.81 obtained for the electric utility industry composite (see Exhibit RAM-2) and a β_w of 0.75 obtained from the natural gas distribution proxy for the wires business (see Exhibit RAM-4), and using industry relative asset weights of approximately 50% and 50% for the generation and wires businesses, the generation business beta can be solved from the above equation:

$$\beta_{vert} = w_w\beta_w + w_g\,\beta_g = 0.50 \text{ x } 0.70 + 0.50 \text{ x } \beta_g = 0.81$$

Solving for β_g, the implied generation beta is 0.87, a result very close to the two estimates of 0.85 obtained earlier from the two proxy generation groups.

Q. PLEASE SUMMARIZE THE VARIOUS BETA ESTIMATES FOR THE T&D AND POWER GENERATION BUSINESSES.

A. The following table summarizes the various beta estimates for the T&D and power generation business.

	Average	
T&D		
S&P Distribution	0.75	
S&P Distribution Elec	0.75	
Natural Gas Distribution	0.74	
GRAND AVERAGE		**0.75**
POWER GENERATION		
S&P Diversified	0.85	
S&P Diversified Elec	0.85	

Oil & Gas	0.85	
Residual Beta	0.87	
GRAND AVERAGE		**0.86**

Q. WHAT IS YOUR FINAL BETA ESTIMATE FOR THE T&D AND POWER GENERATION BUSINESSES?

A. I conclude from the electric utility industry beta distribution analysis, the proxy groups analyses, and from the residual beta analysis that beta estimates for the T&D and generation businesses are 0.75 and 0.86, respectively. The difference in beta between the two businesses is therefore 0.11.

<u>III. C RETURN DIFFERENCES</u>

Q. DR. MORIN, WHAT RETURN DIFFERENCES CAN WE INFER FROM YOUR BETA ESTIMATES FOR THE T&D AND GENERATION BUSINESSES?

A. In order to translate the risk differences between the wires and generation businesses into return differences, I used the CAPM framework. The latter, described earlier in my testimony, can be used to approximate the return (cost of equity) differences implied by the differences in the betas between the individual businesses. The basic form of the CAPM states that the return differential is given by the differential in beta times the market risk premium (R_M- R_F). The return differential implied by the difference in beta of 0.11 between the wires business (0.75) and the generation business (.86) is given by 0.11 times the market risk premium, (R_M-R_F). Using a market risk premium of 7.8% discussed earlier in my testimony, the return adjustment is 86 basis points.

The empirical version of the CAPM formula, described earlier in my testimony, can be also used to approximate the return differences implied by the differences in the betas. The ECAPM states that the return differential is given by the differential in beta times the effective market risk premium of 0.75(R_M- R_F). With a beta differential between the wires and generation businesses of 0.11, the return differential is given by 0.11 times 0.75(R_M- R_F). Using a market risk premium of 7.8%, the return adjustment is 64 basis points.

In summary, the estimates of the return differential between the T&D and the power generation businesses range from 64 to 86 basis points from the CAPM and ECAPM frameworks. I believe that the upper end of this range is indicated, given the downward bias in the historical betas that underlie this range. Historical betas are necessarily downward-biased in assessing the present fluid circumstances of the power industry. By construction, backward-looking betas are sluggish in detecting fundamental changes in a company's risk. Current changes in the fundamentals of the power generation business (high and volatile fuel prices, competition, environmental compliance, regulatory uncertainty, etc.) are not yet fully reflected in historical beta risk measures.

Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING THE COST OF EQUITY CAPITAL FOR THE POWER GENERATION BUSINESS?

A. Given the risk differential of 86 basis points between the T&D and power generation businesses, and given that the power generation and T&D segments represent approximately one half of the vertically integrated utility portfolio, I have adjusted my result of 11.0% for the vertically integrated electric utility industry upward by one-half of the 86 basis points risk increment to 11.4% in order to account for the higher relative risks of the power generation business.

Based on the results of all my analyses and the application of my professional judgment, it is my opinion that a just and reasonable return on common equity on the power generation business is 11.4%.

IV. SUMMARY AND RECOMMENDATION

Q. PLEASE SUMMARIZE YOUR RESULTS.

A. I was asked to conduct an independent appraisal of the cost of common equity capital for PSNH's power generation business. I adopted a two-step procedure. First, I estimated the cost of common equity capital for the vertically integrated electric utility industry. Based on the results of all my analyses and the application of my professional judgment, it is my opinion that a just and reasonable return on common equity for the vertically integrated electric utility industry is 11.0%.

Second, I adjusted the latter estimate upward to account for the higher investment risks of the power generation business. I found that an upward risk adjustment of 43 basis points is reasonable, bringing the cost of common equity capital to 11.4% for the generation business.

To reach that conclusion, I examined various risk measures for companies which are reasonable surrogates for the generation and wires business segments. For the wires business segment, I examined two proxies: a group of energy and water distribution utilities and a group of natural gas distribution utilities. For the generation segment, I examined a group of diversified energy utilities and a group of oil and gas producers, and relied on the residual beta approach.

From the various proxies for the generation business, I found that a reasonable beta estimate for the generation business is 0.86. Coupled with my finding that a reasonable beta estimate for the wires business is 0.75, these results imply that there is a risk differential of 0.11 between the two businesses.

To translate the risk differences into return differences, I used the CAPM and Empirical CAPM frameworks. The return differential implied by the difference in beta between the wires business and the generation business is in the range of 64 – 86 basis points. I chose the upper part of that range, 86 basis points, in order to offset the inherent downward bias in historical beta estimates. Given the relatively equal weight of the T&D and power generation segments, the 86 basis points upward adjustment translates into a differential of 43 basis points between the cost of capital of a vertically integrated electric utility and the power generation business.

Q. IF CAPITAL MARKET CONDITIONS CHANGE SIGNIFICANTLY BETWEEN THE DATE OF FILING YOUR PREPARED TESTIMONY AND THE DATE ORAL TESTIMONY IS PRESENTED, WOULD THIS CAUSE YOU TO REVISE YOUR ESTIMATED COST OF EQUITY?

A. Yes. Interest rates and security prices do change over time, and risk premiums change also, although much more sluggishly. If substantial changes were to occur between the filing date and the time my oral testimony is presented, I will update my testimony accordingly.

Q. WERE EXHIBITS RAM-1 THROUGH RAM-15, AND APPENDICES A AND B, PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

APPENDIX A

CAPM, EMPIRICAL CAPM

A myriad empirical tests of the CAPM have shown that the risk-return tradeoff is not as steeply sloped as that predicted by the CAPM. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. This is one of the most widely known empirical findings of the finance literature. This extensive literature is summarized in Chapter 13 of my book [Regulatory Finance, Public Utilities Report Inc., Arlington, VA, 1994].

Several finance scholars have developed refined and expanded versions of the standard CAPM. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the plain vanilla CAPM prediction. This is exactly what the empirical CAPM accomplishes. It produces a risk-return tradeoff that is flatter than the risk-return tradeoff predicted by the standard CAPM, and better approximates the observed relationship between risk and return in capital markets.

Theoretical Underpinnings

The exclusion of variables aside from beta would produce a risk return relationship which is flatter than the CAPM prediction. Three such variables are noteworthy: dividend yield, skewness, and hedging potential.

The dividend yield effects stem from the differential taxation on corporate dividends and capital gains. The standard CAPM does not consider the regularity of dividends received by investors. Utilities generally maintain high dividend payout ratios relative to the market, and by ignoring dividend yield, the CAPM provides biased cost of capital estimates. To the extent that dividend income is taxed at a higher rate than capital gains, investors will require higher pre-tax returns in order to equalize the after-tax returns provided by high-yielding stocks (e.g. utility stocks) with those of low-yielding stocks. In other words, high-yielding stocks must offer investors higher pre-tax returns. Even if dividends and capital gains are undifferentiated for tax purposes, there is still a tax bias in favor of earnings retention (lower dividend payout), as capital gains taxes are paid only when gains are realized.

Empirical studies by Litzenberger and Ramaswamy (1979), Litzenberger et al. (1980) and Rosenberg and Marathe (1975) find that security returns are positively related to dividend yield as well as to beta. These results are consistent with after-tax extensions of the CAPM developed by Breenan (1973) and Litzenberger and Ramaswamy (1979) and suggest that the relationship between return, beta, and dividend yield should be estimated and employed to calculate the cost of equity capital.

As far as skewness is concerned, investors are more concerned with losing money than with total variability of return. If risk is defined as the probability of loss, it appears more logical to measure risk as the probability of achieving a return which is below the expected return. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant. As shown by Kraus and Litzenberger (1976), expected return depends on both on a stock's systematic risk (beta) and the systematic skewness. Empirical studies by Kraus and Litzenberger (1976), Friend, Westerfield, and Granito (1978), and by me (Morin) (1981) found that, in addition to beta, skewness of returns has a significant negative relationship with security returns. This result is consistent with the skewness version of the CAPM developed by Rubinstein (1973) and Kraus and Litzenberger (1976).

This is particularly relevant for public utilities whose future profitability is constrained by the regulatory process on the upside and relatively unconstrained on the downside in the face of socio-political realities of public utility regulation. The process of regulation, by restricting the upward potential for returns and responding sluggishly on the downward side, may impart some asymmetry to the distribution of returns, and is more likely to result in utilities earning less, rather than more, than their cost of capital. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant.

As far as hedging potential is concerned, investors are exposed to another kind of risk, namely, the risk of unfavorable shifts in the investment opportunity set. Merton (1973) shows that investors will hold portfolios consisting of three funds: the risk-free asset, the market portfolio, and a portfolio whose returns are perfectly negatively correlated with the riskless asset so as to hedge against unforeseen changes in the future risk-free rate. The higher the degree of protection offered by an asset against unforeseen changes in interest rates, the lower the required return, and conversely. Merton argues that low beta assets, like utility stocks, offer little protection against changes in interest rates, and require higher returns than suggested by the standard CAPM.

Another explanation for the CAPM's inability to fully explain the process determining security returns involves the use of an inadequate or incomplete market index. Empirical studies to validate the CAPM invariably rely on some stock market index as a proxy for the true market portfolio. The exclusion of several asset categories from the definition of market index misspecifies the CAPM and biases the results found using only stock market data. Kolbe and Read (1983) illustrate the biases in beta estimates which result from applying the CAPM to public utilities. Unfortunately, no comprehensive and easily accessible data exist for several classes of assets, such as mortgages and business investments, so that the exact relation between return and stock betas predicted by the CAPM does not exist. This suggests that the empirical relationship between returns and stock betas is best estimated empirically (ECAPM) rather than by relying on theoretical and elegant CAPM models expanded to include missing assets effects. In any event, stock betas may be highly correlated with the true beta measured with the true market index.

Yet another explanation for the CAPM's inability to fully explain the observed risk-return tradeoff involves the possibility of constraints on investor borrowing that run counter to the assumptions of the CAPM. In response to this inadequacy, several versions of the CAPM have been developed by researchers. One of these versions is the so-called zero-beta, or two-factor, CAPM which provides for a risk-free return in a market where borrowing and lending rates are divergent. If borrowing rates and lending rates differ, or there is no risk-free borrowing or lending, or there is risk-free lending but no risk-free borrowing, then the CAPM has the following form:

$$K = R_Z + \beta(R_m - R_F)$$

The model, christened the zero-beta model, is analogous to the standard CAPM, but with the return on a minimum risk portfolio which is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who found a flatter than predicted CAPM, consistent with the model and other researchers' findings.

The zero-beta CAPM cannot be literally employed in cost of capital projections, since the zero-beta portfolio is a statistical construct difficult to replicate. Instead, the ECAPM is employed.

Empirical Evidence

The statistical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. For example, over the period 1926-1984, the empirical evidence cited in my publication, Morin, R. A., Regulatory Finance, Public Utility Reports Inc., Arlington, VA, 1994, indicates that the expected return on a security is actually given by the following equation:

$$\text{RETURN} = .0829 + .0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6%, this relationship implies that the intercept of the risk-return relationship is higher than the 6% risk-free rate, contrary to the CAPM's prediction. Given the seminal Ibbotson-Sinquefield result that the average return on an average risk stock exceeds the risk-free rate by about 8.0% in that period, that is, $(R_M - R_F) =$

8%, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2%, or 1/4 of 8%, and the slope of the relationship, .0520, is close to 3/4 of 8%. Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x (R_M - R_F) + (1-x) \beta(R_M - R_F)$$

where x is a fraction to be determined empirically. The value of x was actually derived by systematically varying the constant "x" in that equation from 0 to 1 in steps of 0.05 and choosing that value of 'x' that minimized the mean square error between the observed relationship,

$$\text{RETURN} = .0829 + .0520 \beta$$

and the empirical shortcut CAPM formula. The value of x that best explained the observed relationship was between 0.25 and 0.30. If x = 0.25 in the interest of conservatism, the equation becomes:

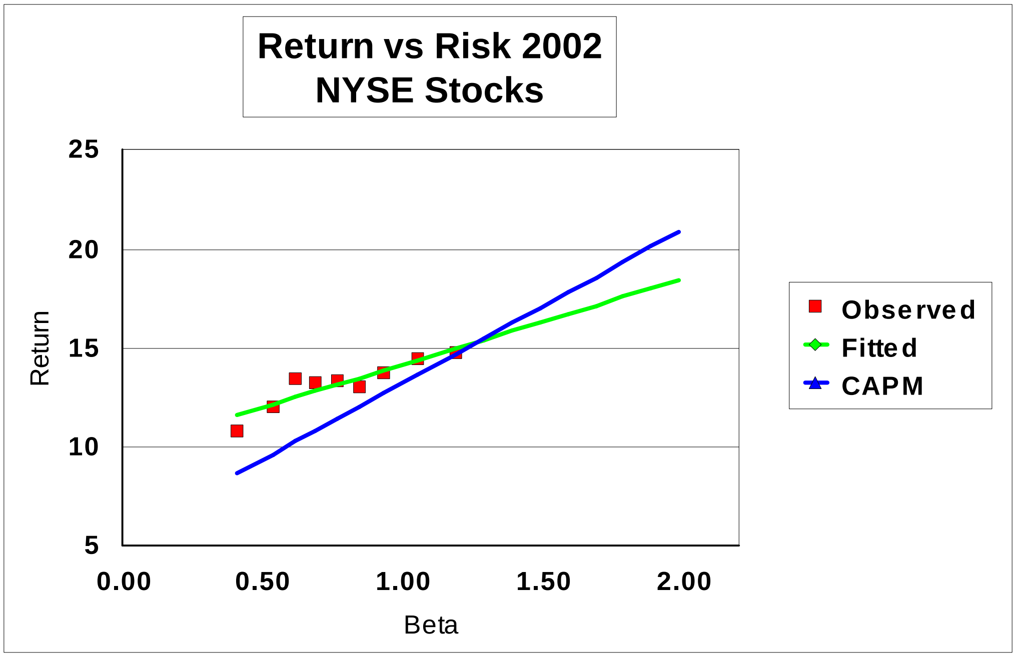
$$K = R_F + 0.25 (R_M - R_F) + 0.75 \beta (R_M - R_F)$$

Most of the empirical studies cited thus far utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. However, a study of the relationship between return and adjusted beta is reported on Table 6-7 in Ibbotson Associates Valuation Yearbook 2001. If we exclude the portfolio of very small cap stocks from the relationship due to significant size effects, the relationship between the arithmetic mean return and beta for the remaining portfolios is flatter than predicted and the intercept slightly higher than predicted by the CAPM. It is noteworthy that the Ibbotson study relies on adjusted betas as stated on page 95 of the aforementioned study.

Another of my studies in May 2002 provided empirical support for the ECAPM. All the stocks covered in the Value Line Investment Survey for Windows for which betas and returns data were available were retained for analysis. There were nearly 2000 such stocks. The expected return was measured as the total shareholder return (“TSR”) reported by Value Line over the past ten years. The Value Line adjusted beta was also retrieved from the same data base. The nearly 2000 companies for which all data were available were ranked in ascending order of beta, from lowest to highest. In order to palliate measurement error, the nearly 2000 securities were grouped into ten portfolios of approximately 180 securities for each portfolio. The average returns and betas for each portfolio were as follows:

Portfolio #	**Beta**	**Return**
portfolio 1	0.41	10.87
portfolio 2	0.54	12.02
portfolio 3	0.62	13.50
portfolio 4	0.69	13.30
portfolio 5	0.77	13.39
portfolio 6	0.85	13.07
portfolio 7	0.94	13.75
portfolio 8	1.06	14.53
portfolio 9	1.19	14.78
portfolio 10	1.48	20.78

It is clear from the graph below that the observed relationship between DCF returns and Value Line adjusted betas is much flatter than that predicted by the plain vanilla CAPM. The observed intercept is higher than the prevailing risk-free rate of 5.7% while the slope is less than equal to the market risk premium of 7.7% predicted by the plain vanilla CAPM for that period.



Evidence from Prospective Risk Premium Studies

In a recent comprehensive article published in Financial Management, Harris, Marsont, Mishra, and O'Brien ("HMMO") estimate ex ante expected returns for S&P 500 companies over the period 1983-1998[1]. Their findings are remarkably consistent with the ECAPM. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. They then investigate the relation between the risk premium (expected return over the 20-year Treasury bond yield) estimates for each month to equity betas as of that same month (5-year raw betas).

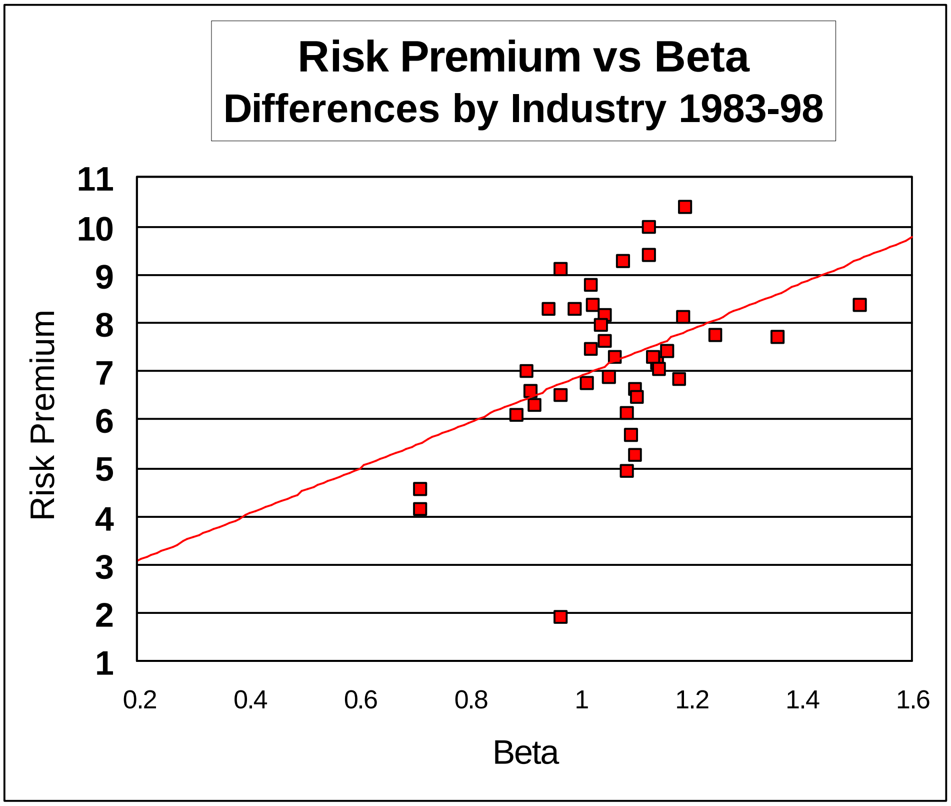
The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill Lynch – Bloomberg adjustment methodology by giving 1/3 weight of to a beta estimate of 1.00 and 2/3 weight to the raw beta estimate.

[1] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

Table A-1 Risk Premium and Beta Estimates by Industry

	Industry (1)	DCF Risk Premium (2)	Raw Industry Beta (3)	Adjusted Industry Beta (4)
1	Aero	6.63	1.15	1.10
2	Autos	5.29	1.15	1.10
3	Banks	7.16	1.21	1.14
4	Beer	6.60	0.87	0.91
5	BldMat	6.84	1.27	1.18
6	Books	7.64	1.07	1.05
7	Boxes	8.39	1.04	1.03
8	BusSv	8.15	1.07	1.05
9	Chems	6.49	1.16	1.11
10	Chips	8.11	1.28	1.19
11	Clths	7.74	1.37	1.25
12	Cnstr	7.70	1.54	1.36
13	Comps	9.42	1.19	1.13
14	Drugs	8.29	0.99	0.99
15	ElcEq	6.89	1.08	1.05
16	Energy	6.29	0.88	0.92
17	Fin	8.38	1.76	1.51
18	Food	7.02	0.86	0.91
19	Fun	9.98	1.19	1.13
20	Gold	4.59	0.57	0.71
21	Hlth	10.40	1.29	1.19
22	Hsld	6.77	1.02	1.01
23	Insur	7.46	1.03	1.02
24	LabEq	7.31	1.10	1.07
25	Mach	7.32	1.20	1.13
26	Meals	7.98	1.06	1.04
27	MedEq	8.80	1.03	1.02
28	Pap	6.14	1.13	1.09
29	PerSv	9.12	0.95	0.97
30	Retail	9.27	1.12	1.08
31	Rubber	7.06	1.22	1.15
32	Ships	1.95	0.95	0.97
33	Stee	4.96	1.13	1.09
34	Telc	6.12	0.83	0.89
35	Toys	7.42	1.24	1.16
36	Trans	5.70	1.14	1.09
37	Txtls	6.52	0.95	0.97
38	Util	4.15	0.57	0.71
39	Whlsl	8.29	0.92	0.95
	MEAN	**7.19**		

The observed statistical relationship between expected return and **adjusted beta** is shown in the graph below:



If the plain vanilla version of the CAPM is correct, then the intercept of the graph should be zero, recalling that the vertical axis represents returns in excess of the risk-free rate. Instead, the observed intercept is approximately 2%, that is approximately equal to 25% of the expected market risk premium of 7.2% shown at the bottom of Column 2 over the 1983-1998 period, as predicted by the ECAPM. The same is true for the slope of the graph. If the plain vanilla version of the CAPM is correct, then the slope of the relationship should equal the market risk premium of 7.2%. Instead, the observed slope of close to 5% is approximately equal to 75% of the expected market risk premium of 7.2%, as predicted by the ECAPM.

In short, the HMMO empirical findings are quite consistent with the predictions of the ECAPM.

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APPENDIX B

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%. In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75% for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.- Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, “The Costs of Raising Capital,” Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5% - 5% for stock issues between $60 and $500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

FLOTATION COSTS: RAISING EXTERNAL CAPITAL
(Percent of Total Capital Raised)

Amount Raised in $ Millions	Average Flotation Cost: Common Stock	Average Flotation Cost: New Debt
$ 2 - 9. 99	13.28%	4.39%
10 - 19. 99	8.72	2.76
20 - 39. 99	6.93	2.42
40 - 59. 99	5.87	1.32
60 - 79. 99	5.18	2.34
80 - 99. 99	4.73	2.16
100 - 199. 99	4.22	2.31
200 - 499. 99	3.47	2.19
500 and Up	3.15	1.64

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than $10 million and about 6 percent if more than $500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research,* Spring 1996.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_o + g$$

If P_o is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_o equals B_o, the book value per share, then the company's required return is:

$$r = D_1/B_o + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_o are related to market price P_o as follows:

$$P - fP = B_o$$

$$P(1 - f) = B_o$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1-f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 7-9 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 7. The stock is selling in the market for $25, investors expect the firm to pay a dividend of $2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus k = D/P + g = 2.25/25 + .05 = 14%. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus ROE = D/P(1-f) + g = .09/.95 + .05 = 14.47%.

The initial book value (rate base) is the net proceeds from the stock issue, which are \$23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at \$2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from \$26.25 to \$26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE =	$25.00
FLOTATION COST =	5.00%
DIVIDEND YIELD =	9.00%
GROWTH =	5.00%
EQUITY RETURN =	**14.00%**
(D/P + g)	
ALLOWED RETURN ON EQUITY =	**14.47%**
(D/P(1-f) + g)	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
--------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.438	$2.250	65.45%
2	$23.75	$1.188	$24.938	$26.250	1.0526	$3.609	$2.363	65.45%
3	$23.75	$2.434	$26.184	$27.563	1.0526	$3.790	$2.481	65.45%
4	$23.75	$3.744	$27.494	$28.941	1.0526	$3.979	$2.605	65.45%
5	$23.75	$5.118	$28.868	$30.388	1.0526	$4.178	$2.735	65.45%
6	$23.75	$6.562	$30.312	$31.907	1.0526	$4.387	$2.872	65.45%
7	$23.75	$8.077	$31.827	$33.502	1.0526	$4.607	$3.015	65.45%
8	$23.75	$9.669	$33.419	$35.178	1.0526	$4.837	$3.166	65.45%
9	$23.75	$11.340	$35.090	$36.936	1.0526	$5.079	$3.324	65.45%
10	$23.75	$13.094	$36.844	$38.783	1.0526	$5.333	$3.490	65.45%
			5.00%	**5.00%**		**5.00%**	**5.00%**	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.325	$2.250	67.67%
2	$23.75	$1.075	$24.825	$26.132	1.0526	$3.476	$2.352	67.67%
3	$23.75	$2.199	$25.949	$27.314	1.0526	$3.633	$2.458	67.67%
4	$23.75	$3.373	$27.123	$28.551	1.0526	$3.797	$2.570	67.67%
5	$23.75	$4.601	$28.351	$29.843	1.0526	$3.969	$2.686	67.67%
6	$23.75	$5.884	$29.634	$31.194	1.0526	$4.149	$2.807	67.67%
7	$23.75	$7.225	$30.975	$32.606	1.0526	$4.337	$2.935	67.67%
8	$23.75	$8.627	$32.377	$34.082	1.0526	$4.533	$3.067	67.67%
9	$23.75	$10.093	$33.843	$35.624	1.0526	$4.738	$3.206	67.67%
10	$23.75	$11.625	$35.375	$37.237	1.0526	$4.952	$3.351	67.67%
			4.53%	**4.53%**		**4.53%**	**4.53%**	

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EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.

- Master of Business Administration, McGill University, Montreal, Canada, 1969.

- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pa., 1972-3

- Assistant Professor, University of Montreal School of Business, 1973-1976.

- Associate Professor, University of Montreal School of Business, 1976-1979.

- Professor of Finance, Georgia State University, 1979-2005

- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, College of Business, Georgia State University, 1985-2005

- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.

- Member of the Board of Directors, Financial Research Institute of Canada, 1974-1980.

- Co-founder and Director Canadian Finance Research Foundation, 1977.

- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.

- Executive Visions Inc., Board of Directors, Member

- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991

PROFESSIONAL CLIENTS

AGL Resources

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

Ameren

American Water Works Company

Ameritech

Arkansas Western Gas

Baltimore Gas & Electric – Constellation Energy

B.C. Telephone

B C GAS

Bell Canada

Bellcore

Bell South Corp.

Bruncor (New Brunswick Telephone)

Burlington-Northern

C & S Bank

Cajun Electric

Canadian Radio-Television & Telecomm. Commission

Canadian Utilities

Canadian Western Natural Gas

Centel

Centra Gas

Central Illinois Light & Power Co.

Central Telephone

PROFESSIONAL CLIENTS (CONT'D)

Central & South West Corp.

Chattanoogee Gas Company

Cincinnati Gas & Electric

Cinergy Corp.

Citizens Utilities

City Gas of Florida

CN-CP Telecommunications

Commonwealth Telephone Co.

Columbia Gas System

Consolidated Natural Gas

Constellation Energy

Deerpath Group

Edison International

Edmonton Power Company

Elizabethtown Gas Co.

Energen

Engraph Corporation

Entergy Corp.

Entergy Arkansas Inc.

Entergy Gulf States, Inc.

Entergy Louisiana, Inc.

Entergy New Orleans, Inc.

First Energy

Florida Water Association

Fortis

Garmaise-Thomson & Assoc., Investment Consultants

PROFESSIONAL CLIENTS (CONT'D)

Gaz Metropolitain

General Public Utilities

Georgia Broadcasting Corp.

Georgia Power Company

GTE California - Verizon

GTE Northwest Inc. - Verizon

GTE Service Corp. - Verizon

GTE Southwest Incorporated - Verizon

Gulf Power Company

Havasu Water Inc.

Heater Utilities – Aqua - America

Hope Gas Inc.

Hydro-Quebec

ICG Utilities

Illinois Commerce Commission

Island Telephone

Jersey Central Power & Light

Kansas Power & Light

KeySpan Energy

Manitoba Hydro

Maritime Telephone

Metropolitan Edison Co.

Minister of Natural Resources Province of Quebec

Minnesota Power & Light

Mississippi Power Company

Missouri Gas Energy

PROFESSIONAL CLIENTS (CONT'D)

Mountain Bell

Nevada Power Company

New Brunswick Power

Newfoundland Power Inc. - Fortis Inc.

New Tel Enterprises Ltd.

New York Telephone Co.

Norfolk-Southern

Northern Telephone Ltd.

Northwestern Bell

Northwestern Utilities Ltd.

Nova Scotia Power – Emera Inc.

Nova Scotia Utility and Review Board

NUI Corp.

NYNEX

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

Pacific Northwest Bell

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Price Waterhouse

PSI Energy

Public Service Electric & Gas

Quebec Telephone

Regie de l’Energie du Quebec

PROFESSIONAL CLIENTS (CONT'D)

Rochester Telephone

San Diego Gas & Electric

SaskPower

Sierra Pacific Power Company

Sierra Pacific Resources

Southern Bell

Southern States Utilities

Southern Union Gas

South Central Bell

Sun City Water Company

TECO Energy

The Southern Company

Touche Ross and Company

TransEnergie

Trans-Quebec & Maritimes Pipeline

TXU Corp

US WEST Communications

Union Heat Light & Power

Utah Power & Light

Vermont Gas Systems Inc.

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73

- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75

- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78

- Investment Dealers Association of Canada, 1977-78

- Financial Research Foundation, bi-annual seminar, 1975-79

- Advanced Management Research (AMR), faculty member, 1977-80

- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar

- Exnet Inc. a.k.a. The Management Exchange Inc., faculty member, 1981-2004, National Seminars:

  Risk and Return on Capital Projects
  Cost of Capital for Regulated Utilities
  Capital Allocation for Utilities
  Alternative Regulatory Frameworks
  Utility Directors' Workshop
  Shareholder Value Creation for Utilities
  Real Options in Utility Capital Investments
  Fundamentals of Utility Finance in a Restructured Environment
  Contemporary Issues in Utility Finance

- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Rate of Return

Capital Structure

Generic Cost of Capital

Costing Methodology

Depreciation

Flow-Through vs Normalization

Revenue Requirements Methodology

Utility Capital Expenditures Analysis

Risk Analysis

Capital Allocation

Divisional Cost of Capital, Unbundling

Incentive Regulation & Alternative Regulatory Plans

Shareholder Value Creation

Value-Based Management

REGULATORY BODIES

Federal Communications Commission

Federal Energy Regulatory Commission

Georgia Public Service Commission

South Carolina Public Service Commission

North Carolina Utilities Commission

Pennsylvania Public Service Commission

Ontario Telephone Service Commission

Quebec Telephone Service Commission

Newfoundland Board of Commissioners of Public Utilities

Georgia Senate Committee on Regulated Industries

Alberta Public Service Board

Tennessee Regulatory Authority

Oklahoma State Board of Equalization

Mississippi Public Service Commission

Minnesota Public Utilities Commission

Canadian Radio-Television & Telecommunications Comm.

New Brunswick Board of Public Commissioners

Alaska Public Utility Commission

National Energy Board of Canada

Florida Public Service Commission

Montana Public Service Commission

Arizona Corporation Commission

Quebec Natural Gas Board

Quebec Regie de l'Energie

New York Public Service Commission

Washington Utilities & Transportation Commission

Manitoba Board of Public Utilities

New Jersey Board of Public Utilities

Alabama Public Service Commission

Utah Public Service Commission

Nevada Public Service Commission

Louisiana Public Service Commission

Colorado Public Utilities Board

West Virginia Public Service Commission

Ohio Public Utilities Commission

California Public Service Commission

Hawaii Public Service Commission

Illinois Commerce Commission

British Columbia Board of Public Utilities

Indiana Utility Regulatory Commission

Minnesota Public Utilities Commission

Texas Public Utility Commission

Michigan Public Service Commission

Iowa Board of Public Utilities

Missouri Public Service Commission

Arkansas Public Service Commission

SERVICE AS EXPERT WITNESS

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Quebec Northern Telephone, Quebec PSC

Edmonton Power Company, Alberta Public Service Board

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NYNEX, FCC generic cost of capital Docket #84-800

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Gulf Power, Florida PSC, Case # 891345-EI

ICG Utilities, Manitoba BPU, Case 1989

New Tel Enterprises, CRTC, Docket #90-15

Peoples Gas Systems, Florida PSC

Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J

Alabama Gas Co., Alabama PSC, Case 890001

Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board

Mountain Bell, Utah PSC,

Mountain Bell, Colorado PUB

South Central Bell, Louisiana PS

Hope Gas, West Virginia PSC

Vermont Gas Systems, Vermont PSC

Alberta Power Ltd., Alberta PUB

Ohio Utilities Company, Ohio PSC

Georgia Power Company, Georgia PSC

Sun City Water Company

Havasu Water Inc.

Centra Gas (Manitoba) Co.

Central Telephone Co. Nevada

AGT Ltd., CRTC 1992

BC GAS, BCPUB 1992

California Water Association, California PUC 1992

Maritime Telephone 1993

BCE Enterprises, Bell Canada, 1993

Citizens Utilities Arizona gas division 1993

PSI Resources 1993-5

CILCORP gas division 1994

GTE Northwest Oregon 1993

Stentor Group 1994-5

Bell Canada 1994-1995

PSI Energy 1993, 1994, 1995, 1999

Cincinnati Gas & Electric 1994, 1996, 1999, 2004

Southern States Utilities, 1995

CILCO 1995, 1999, 2001

Commonwealth Telephone 1996

Edison International 1996, 1998

Citizens Utilities 1997

Stentor Companies 1997

Hydro-Quebec 1998

Entergy Gulf States Louisiana 1998, 1999, 2001, 2002, 2003

Detroit Edison, 1999, 2003

Entergy Gulf States, Texas, 2000, 2004

Hydro Quebec TransEnergie, 2001, 2004

Sierra Pacific Company, 2000, 2001, 2002

Nevada Power Company, 2001

Mid American Energy, 2001, 2002

Entergy Louisiana Inc. 2001, 2002, 2004

Mississippi Power Company, 2001, 2002

Oklahoma Gas & Electric Company, 2002 -2003

Public Service Electric & Gas, 2001, 2002

NUI Corp (Elizabethtown Gas Company), 2002

Jersey Central Power & Light, 2002

San Diego Gas & Electric, 2002

NB Power, 2002

Entergy New Orleans, 2002

Hydro-Quebec Distribution 2002

PSI Energy 2003

Fortis – Newfoundland Power & Light 2002

Emera – Nova Scotia Power 2004

Hydro-Quebec TransEnergie 2004

Hawaiian Electric 2004

Missouri Gas Energy 2004

AGL Resources 2004

Arkansas Western Gas 2004

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982

- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982

- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983

- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.

- Committee on New Product Development, FMA, 1985

- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986

- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986

- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fla., 1988.

PAPERS PRESENTED:

"An Empirical Study of Multi-Period Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation
"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, l978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977

- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975

- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976

- Member, New Product Development Committee, Financial Management Association, 1985-1986

- Reviewer: Journal of Financial Research

  Financial Management

  Financial Review

  Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital," Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. l982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978.

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981.

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994.

Driving Shareholder Value, McGraw-Hill, January 2001.

The New Regulatory Finance, forthcoming 2005.

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980. (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

“An Economic & Financial Profile of the Canadian Cablevision Industry,” Canadian Radio-Television & Telecommunication Commission (CRTC), 1978.

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

“Operational Risk Analysis: California Water Utilities,” Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company,1985.

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique",CRTC,1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement, 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Econometric Planning Model of the Cablevision Industry", International Institute of Quantitative Economics, CRTC.

"Application of the Averch-Johnson Model to Telecommunications Utilities", Canadian Radio-Television Commission. (CRTC)

"Economics of the Fiber Optics Industry", Quebec Dept. of Communications.

"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981.

"Firm Size and Beta Stability", Georgia State University College of Business, 1982.

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

Chase Econometrics, Interactive Data Corp., Research Grant, $50,000 per annum, 1986-1989.

UNIVERSITY SERVICE

- University Senate, elected departmental senator 1987-1989, 1998-2002
- Faculty Affairs Committee, elected departmental representative
- Professional Continuing Education Committee member
- Director Master in Science (Finance) Program
- Course Coordinator, Corporate Finance, MBA program
- Chairman, Corporate Finance Curriculum Committee
- Executive Education: Departmental Coordinator 2000

MOODY'S ELECTRIC UTILITIES
BETA ESTIMATES

	Company Name	Beta
1	Amer. Elec. Power	1.15
2	CH Energy Group	0.80
3	Cinergy Corp.	0.80
4	Consol. Edison	0.60
5	Constellation Energy	0.85
6	Dominion Resources	0.85
7	DPL Inc.	0.90
8	Duquesne Light Hldgs	0.75
9	Duke Energy	1.10
10	Energy East Corp.	0.80
11	Exelon Corp.	0.70
12	FirstEnergy Corp.	0.75
13	IDACORP Inc.	0.85
14	NiSource Inc.	0.75
15	OGE Energy	0.70
16	PPL Corp.	0.95
17	Progress Energy	0.80
18	Public Serv. Enterprise	0.85
19	Southern Co.	0.65
20	TECO Energy	0.90
21	Xcel Energy Inc.	0.80
	AVERAGE	**0.82**

ELECTRIC UTILITY INDUSTRY
BETA ESTIMATES

	Company Name	Industry	Beta
1	Allegheny Energy	UTILEAST	
2	Alliant Energy	UTILCENT	0.80
3	Amer. Elec. Power	UTILCENT	1.15
4	Ameren Corp.	UTILCENT	0.75
5	Aquila Inc.	UTILCENT	1.25
6	Avista Corp.	UTILWEST	0.90
7	Black Hills	UTILWEST	0.95
8	CH Energy Group	UTILEAST	0.80
9	CMS Energy Corp.	UTILCENT	1.30
10	Cen. Vermont Pub. Serv.	UTILEAST	0.50
11	CenterPoint Energy	UTILCENT	0.55
12	Cinergy Corp.	UTILCENT	0.80
13	Cleco Corp.	UTILCENT	1.10
14	Consol. Edison	UTILEAST	0.60
15	Constellation Energy	UTILEAST	0.85
16	DPL Inc.	UTILCENT	0.90
17	DTE Energy	UTILCENT	0.70
18	Dominion Resources	UTILEAST	0.85
19	Duke Energy	UTILEAST	1.10
20	Duquesne Light Hldgs	UTILEAST	0.75
21	Edison Int'l	UTILWEST	1.05
22	El Paso Electric	UTILWEST	0.65
23	Empire Dist. Elec.	UTILCENT	0.70
24	Energy East Corp.	UTILEAST	0.80
25	Entergy Corp.	UTILCENT	0.75
26	Exelon Corp.	UTILEAST	0.70
27	FPL Group	UTILEAST	0.70
28	FirstEnergy Corp.	UTILEAST	0.75
29	Florida Public Utilities	UTILEAST	0.60
30	G't Plains Energy	UTILCENT	0.80
31	Green Mountain Pwr.	UTILEAST	0.60
32	Hawaiian Elec.	UTILWEST	0.65
33	IDACORP Inc.	UTILWEST	0.85
34	MDU Resources	UTILWEST	0.85
35	MGE Energy	UTILCENT	0.60
36	Maine & Maritimes Corp	UTILEAST	0.45
37	NSTAR	UTILEAST	0.70
38	NiSource Inc.	UTILCENT	0.75
39	NorthWestern Corporation	UTILCENT	1.10
40	Northeast Utilities	UTILEAST	0.75
41	OGE Energy	UTILCENT	0.70
42	Otter Tail Corp.	UTILCENT	0.60
43	PG&E Corp.	UTILWEST	1.00
44	PNM Resources	UTILWEST	0.85
45	PPL Corp.	UTILEAST	0.95
46	Pepco Holdings	UTILEAST	0.85
47	Pinnacle West Capital	UTILWEST	0.85
48	Progress Energy	UTILEAST	0.80
49	Public Serv. Enterprise	UTILEAST	0.85
50	Puget Energy Inc.	UTILWEST	0.75
51	SCANA Corp.	UTILEAST	0.70
52	Sempra Energy	UTILWEST	0.90
53	Sierra Pacific Res.	UTILWEST	1.00
54	Southern Co.	UTILEAST	0.65
55	TECO Energy	UTILEAST	0.90
56	TXU Corp.	UTILCENT	1.00
57	UIL Holdings	UTILEAST	0.80
58	UNITIL Corp.	UTILEAST	0.35
59	UniSource Energy	UTILWEST	0.65
60	Vectren Corp.	UTILCENT	0.75
61	WPS Resources	UTILCENT	0.75
62	Westar Energy	UTILCENT	0.75
63	Wisconsin Energy	UTILCENT	0.70
64	Xcel Energy Inc.	UTILWEST	0.80
	AVERAGE		**0.80**
	MEDIAN		**0.80**
	TRUNCATED MEAN		**0.80**
	STD DEVIATION		**0.18**

Source: VLIA 02/2005

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Electric Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1931	4.07%	1,000.00				43.23					
1932	3.15%	1,135.75	135.75	40.70	17.64%	39.42	2.63	-8.81%	6.08%	-2.73%	-20.37%
1933	3.36%	969.60	(30.40)	31.50	0.11%	28.73	1.95	-27.12%	4.95%	-22.17%	-22.28%
1934	2.93%	1,064.73	64.73	33.60	9.83%	21.06	1.60	-26.70%	5.57%	-21.13%	-30.96%
1935	2.76%	1,025.99	25.99	29.30	5.53%	36.06	1.32	71.23%	6.27%	77.49%	71.96%
1936	2.55%	1,032.74	32.74	27.60	6.03%	41.60	1.48	15.36%	4.10%	19.47%	13.43%
1937	2.73%	972.40	(27.60)	25.50	-0.21%	24.24	1.74	-41.73%	4.18%	-37.55%	-37.34%
1938	2.52%	1,032.83	32.83	27.30	6.01%	27.55	1.50	13.66%	6.19%	19.84%	13.83%
1939	2.26%	1,041.65	41.65	25.20	6.68%	28.85	1.48	4.72%	5.37%	10.09%	3.41%
1940	1.94%	1,052.84	52.84	22.60	7.54%	22.22	1.54	-22.98%	5.34%	-17.64%	-25.19%
1941	2.04%	983.64	(16.36)	19.40	0.30%	13.45	1.44	-39.47%	6.48%	-32.99%	-33.29%
1942	2.46%	933.97	(66.03)	20.40	-4.56%	14.29	1.26	6.25%	9.37%	15.61%	20.18%
1943	2.48%	996.86	(3.14)	24.60	2.15%	21.01	1.28	47.03%	8.96%	55.98%	53.84%
1944	2.46%	1,003.14	3.14	24.80	2.79%	21.09	1.31	0.38%	6.24%	6.62%	3.82%
1945	1.99%	1,077.23	77.23	24.60	10.18%	31.14	1.30	47.65%	6.16%	53.82%	43.63%
1946	2.12%	978.90	(21.10)	19.90	-0.12%	32.71	1.43	5.04%	4.59%	9.63%	9.75%
1947	2.43%	951.13	(48.87)	21.20	-2.77%	25.60	1.56	-21.74%	4.77%	-16.97%	-14.20%
1948	2.37%	1,009.51	9.51	24.30	3.38%	26.20	1.60	2.34%	6.25%	8.59%	5.21%
1949	2.09%	1,045.58	45.58	23.70	6.93%	30.57	1.66	16.68%	6.34%	23.02%	16.09%
1950	2.24%	975.93	(24.07)	20.90	-0.32%	30.81	1.76	0.79%	5.76%	6.54%	6.86%
1951	2.69%	930.75	(69.25)	22.40	-4.69%	33.85	1.88	9.87%	6.10%	15.97%	20.65%
1952	2.79%	984.75	(15.25)	26.90	1.17%	37.85	1.91	11.82%	5.64%	17.46%	16.29%
1953	2.74%	1,007.66	7.66	27.90	3.56%	39.61	2.01	4.65%	5.31%	9.96%	6.40%
1954	2.72%	1,003.07	3.07	27.40	3.05%	47.56	2.13	20.07%	5.38%	25.45%	22.40%
1955	2.95%	965.44	(34.56)	27.20	-0.74%	49.35	2.21	3.76%	4.65%	8.41%	9.15%
1956	3.45%	928.19	(71.81)	29.50	-4.23%	48.96	2.32	-0.79%	4.70%	3.91%	8.14%
1957	3.23%	1,032.23	32.23	34.50	6.67%	50.30	2.43	2.74%	4.96%	7.70%	1.03%
1958	3.82%	918.01	(81.99)	32.30	-4.97%	66.37	2.50	31.95%	4.97%	36.92%	41.89%
1959	4.47%	914.65	(85.35)	38.20	-4.71%	65.77	2.61	-0.90%	3.93%	3.03%	7.74%
1960	3.80%	1,093.27	93.27	44.70	13.80%	76.82	2.68	16.80%	4.07%	20.88%	7.08%

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Electric Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1961	4.15%	952.75	(47.25)	38.00	-0.92%	99.32	2.81	29.29%	3.66%	32.95%	33.87%
1962	3.95%	1,027.48	27.48	41.50	6.90%	96.49	2.97	-2.85%	2.99%	0.14%	-6.76%
1963	4.17%	970.35	(29.65)	39.50	0.99%	102.31	3.21	6.03%	3.33%	9.36%	8.37%
1964	4.23%	991.96	(8.04)	41.70	3.37%	115.54	3.43	12.93%	3.35%	16.28%	12.92%
1965	4.50%	964.64	(35.36)	42.30	0.69%	114.86	3.86	-0.59%	3.34%	2.75%	2.06%
1966	4.55%	993.48	(6.52)	45.00	3.85%	105.99	4.11	-7.72%	3.58%	-4.14%	-7.99%
1967	5.56%	879.01	(120.99)	45.50	-7.55%	98.19	4.34	-7.36%	4.09%	-3.26%	4.29%
1968	5.98%	951.38	(48.62)	55.60	0.70%	104.04	4.50	5.96%	4.58%	10.54%	9.84%
1969	6.87%	904.00	(96.00)	59.80	-3.62%	84.62	4.61	-18.67%	4.43%	-14.23%	-10.62%
1970	6.48%	1,043.38	43.38	68.70	11.21%	88.59	4.70	4.69%	5.55%	10.25%	-0.96%
1971	5.97%	1,059.09	59.09	64.80	12.39%	85.56	4.77	-3.42%	5.38%	1.96%	-10.42%
1972	5.99%	997.69	(2.31)	59.70	5.74%	83.61	4.87	-2.28%	5.69%	3.41%	-2.33%
1973	7.26%	867.09	(132.91)	59.90	-7.30%	60.87	5.01	-27.20%	5.99%	-21.21%	-13.90%
1974	7.60%	965.33	(34.67)	72.60	3.79%	41.17	4.83	-32.36%	7.93%	-24.43%	-28.22%
1975	8.05%	955.63	(44.37)	76.00	3.16%	55.66	4.97	35.20%	12.07%	47.27%	44.10%
1976	7.21%	1,088.25	88.25	80.50	16.87%	66.29	5.18	19.10%	9.31%	28.40%	11.53%
1977	8.03%	919.03	(80.97)	72.10	-0.89%	68.19	5.54	2.87%	8.36%	11.22%	12.11%
1978	8.98%	912.47	(87.53)	80.30	-0.72%	59.75	5.81	-12.38%	8.52%	-3.86%	-3.13%
1979	10.12%	902.99	(97.01)	89.80	-0.72%	56.41	6.22	-5.59%	10.41%	4.82%	5.54%
1980	11.99%	859.23	(140.77)	101.20	-3.96%	54.42	6.58	-3.53%	11.66%	8.14%	12.09%
1981	13.34%	906.45	(93.55)	119.90	2.63%	57.20	6.99	5.11%	12.84%	17.95%	15.32%
1982	10.95%	1,192.38	192.38	133.40	32.58%	70.26	7.43	22.83%	12.99%	35.82%	3.24%
1983	11.97%	923.12	(76.88)	109.50	3.26%	72.03	7.87	2.52%	11.20%	13.72%	10.46%
1984	11.70%	1,020.70	20.70	119.70	14.04%	80.16	8.26	11.29%	11.47%	22.75%	8.71%
1985	9.56%	1,189.27	189.27	117.00	30.63%	94.98	8.61	18.49%	10.74%	29.23%	-1.40%
1986	7.89%	1,166.63	166.63	95.60	26.22%	113.66	8.89	19.67%	9.36%	29.03%	2.80%
1987	9.20%	881.17	(118.83)	78.90	-3.99%	94.24	9.12	-17.09%	8.02%	-9.06%	-5.07%
1988	9.18%	1,001.82	1.82	92.00	9.38%	100.94	8.87	7.11%	9.41%	16.52%	7.14%
1989	8.16%	1,099.75	99.75	91.80	19.16%	122.52	8.82	21.38%	8.74%	30.12%	10.96%
1990	8.44%	973.17	(26.83)	81.60	5.48%	117.77	8.79	-3.88%	7.17%	3.30%	-2.18%

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Electric Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1991	7.30%	1,118.94	118.94	84.40	20.33%	144.02	8.95	22.29%	7.60%	29.89%	9.55%
1992	7.26%	1,004.19	4.19	73.00	7.72%	141.06	9.05	-2.06%	6.28%	4.23%	-3.49%
1993	6.54%	1,079.70	79.70	72.60	15.23%	146.70	8.99	4.00%	6.37%	10.37%	-4.86%
1994	7.99%	856.40	(143.60)	65.40	-7.82%	115.50	8.96	-21.27%	6.11%	-15.16%	-7.34%
1995	6.03%	1,225.98	225.98	79.90	30.59%	142.90	9.06	23.72%	7.84%	31.57%	0.98%
1996	6.73%	923.67	(76.33)	60.30	-1.60%	136.00	9.06	-4.83%	6.34%	1.51%	3.11%
1997	6.02%	1,081.92	81.92	67.30	14.92%	155.73	9.06	14.51%	6.66%	21.17%	6.25%
1998	5.42%	1,072.71	72.71	60.20	13.29%	181.44	8.01	16.51%	5.14%	21.65%	8.36%
1999	6.82%	848.41	(151.59)	54.20	-9.74%	137.30	8.06	-24.33%	4.44%	-19.89%	-10.15%
2000	5.58%	1,148.30	148.30	68.20	21.65%	227.09	8.71	65.40%	6.34%	71.74%	50.09%
2001	5.75%	979.95	(20.05)	55.80	3.57%	214.08	8.56	-5.73%	3.77%	-1.96%	-5.54%
Mean											**5.55%**

Source: Mergent's (Moody's) Public Utility Manual 2002 December stock prices and dividends
Dec. Bond yields from Ibbotson Associates 2002 Yearbook Table B-9 Long-Term Government Bonds Yields

MOODY'S NATURAL GAS DISTRIBUTION COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Governmen Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Natural Gas Distribution Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1954	2.72%	1,000.00				26.47					
1955	2.95%	965.44	(34.56)	27.20	-0.74%	28.10	1.38	6.16%	5.21%	11.37%	12.11%
1956	3.45%	928.19	(71.81)	29.50	-4.23%	28.23	1.48	0.46%	5.27%	5.73%	9.96%
1957	3.23%	1,032.23	32.23	34.50	6.67%	25.78	1.49	-8.68%	5.28%	-3.40%	-10.07%
1958	3.82%	918.01	(81.99)	32.30	-4.97%	38.71	1.57	50.16%	6.09%	56.25%	61.21%
1959	4.47%	914.65	(85.35)	38.20	-4.71%	39.59	1.66	2.27%	4.29%	6.56%	11.28%
1960	3.80%	1,093.27	93.27	44.70	13.80%	48.21	1.84	21.77%	4.65%	26.42%	12.62%
1961	4.15%	952.75	(47.25)	38.00	-0.92%	64.96	1.94	34.74%	4.02%	38.77%	39.69%
1962	3.95%	1,027.48	27.48	41.50	6.90%	59.73	2.02	-8.05%	3.11%	-4.94%	-11.84%
1963	4.17%	970.35	(29.65)	39.50	0.99%	64.62	2.18	8.19%	3.65%	11.84%	10.85%
1964	4.23%	991.96	(8.04)	41.70	3.37%	68.24	2.30	5.60%	3.56%	9.16%	5.80%
1965	4.50%	964.64	(35.36)	42.30	0.69%	64.31	2.48	-5.76%	3.63%	-2.12%	-2.82%
1966	4.55%	993.48	(6.52)	45.00	3.85%	53.50	2.61	-16.81%	4.06%	-12.75%	-16.60%
1967	5.56%	879.01	(120.99)	45.50	-7.55%	50.49	2.74	-5.63%	5.12%	-0.50%	7.04%
1968	5.98%	951.38	(48.62)	55.60	0.70%	53.80	2.81	6.56%	5.57%	12.12%	11.42%
1969	6.87%	904.00	(96.00)	59.80	-3.62%	43.88	2.93	-18.44%	5.45%	-12.99%	-9.37%
1970	6.48%	1,043.38	43.38	68.70	11.21%	52.33	3.01	19.26%	6.86%	26.12%	14.91%
1971	5.97%	1,059.09	59.09	64.80	12.39%	47.86	3.07	-8.54%	5.87%	-2.68%	-15.06%
1972	5.99%	997.69	(2.31)	59.70	5.74%	53.54	3.12	11.87%	6.52%	18.39%	12.65%
1973	7.26%	867.09	(132.91)	59.90	-7.30%	43.43	3.28	-18.88%	6.13%	-12.76%	-5.46%
1974	7.60%	965.33	(34.67)	72.60	3.79%	29.71	3.34	-31.59%	7.69%	-23.90%	-27.69%
1975	8.05%	955.63	(44.37)	76.00	3.16%	38.29	3.48	28.88%	11.71%	40.59%	37.43%
1976	7.21%	1,088.25	88.25	80.50	16.87%	51.80	3.70	35.28%	9.66%	44.95%	28.07%
1977	8.03%	919.03	(80.97)	72.10	-0.89%	50.88	3.93	-1.78%	7.59%	5.81%	6.70%
1978	8.98%	912.47	(87.53)	80.30	-0.72%	45.97	4.18	-9.65%	8.22%	-1.43%	-0.71%
1979	10.12%	902.99	(97.01)	89.80	-0.72%	53.50	4.44	16.38%	9.66%	26.04%	26.76%
1980	11.99%	859.23	(140.77)	101.20	-3.96%	56.61	4.68	5.81%	8.75%	14.56%	18.52%
1981	13.34%	906.45	(93.55)	119.90	2.63%	53.50	5.12	-5.49%	9.04%	3.55%	0.92%
1982	10.95%	1,192.38	192.38	133.40	32.58%	50.62	5.39	-5.38%	10.07%	4.69%	-27.89%
1983	11.97%	923.12	(76.88)	109.50	3.26%	55.79	5.55	10.21%	10.96%	21.18%	17.92%
1984	11.70%	1,020.70	20.70	119.70	14.04%	69.70	5.88	24.93%	10.54%	35.47%	21.43%
1985	9.56%	1,189.27	189.27	117.00	30.63%	76.58	6.22	9.87%	8.92%	18.79%	-11.83%
1986	7.89%	1,166.63	166.63	95.60	26.22%	90.89	5.71	18.69%	7.46%	26.14%	-0.08%
1987	9.20%	881.17	(118.83)	78.90	-3.99%	77.25	6.02	-15.01%	6.62%	-8.38%	-4.39%
1988	9.18%	1,001.82	1.82	92.00	9.38%	86.76	6.30	12.31%	8.16%	20.47%	11.08%
1989	8.16%	1,099.75	99.75	91.80	19.16%	117.05	6.58	34.91%	7.58%	42.50%	23.34%
1990	8.44%	973.17	(26.83)	81.60	5.48%	108.86	6.84	-7.00%	5.84%	-1.15%	-6.63%
1991	7.30%	1,118.94	118.94	84.40	20.33%	124.32	6.99	14.20%	6.42%	20.62%	0.29%
1992	7.26%	1,004.19	4.19	73.00	7.72%	138.79	7.14	11.64%	5.74%	17.38%	9.66%
1993	6.54%	1,079.70	79.70	72.60	15.23%	154.06	7.30	11.00%	5.26%	16.26%	1.03%
1994	7.99%	856.40	(143.60)	65.40	-7.82%	126.96	7.44	-17.59%	4.83%	-12.76%	-4.94%
1995	6.03%	1,225.98	225.98	79.90	30.59%	155.94	7.56	22.83%	5.95%	28.78%	-1.81%
1996	6.73%	923.67	(76.33)	60.30	-1.60%	166.64	7.91	6.86%	5.07%	11.93%	13.54%
1997	6.02%	1,081.92	81.92	67.30	14.92%	191.04	8.02	14.64%	4.81%	19.46%	4.53%
1998	5.42%	1,072.71	72.71	60.20	13.29%	177.24	8.13	-7.22%	4.26%	-2.97%	-16.26%
1999	6.82%	848.41	(151.59)	54.20	-9.74%	166.84	8.22	-5.87%	4.64%	-1.23%	8.51%
2000	5.58%	1,148.30	148.30	68.20	21.65%	200.68	8.22	20.28%	4.93%	25.21%	3.56%
2001	5.75%	979.95	61.94	51.23	11.87%	209.67	8.22	4.48%	4.10%	8.58%	-3.29%
MEAN					**6.50%**					**12.16%**	**5.66%**

Source: Mergent's (Moody's) Public Utility Manual 2002 December stock prices and dividends
Bond yields from Ibbotson Associates 2002 Yearbook Table B-9 Long-Term Government Bonds Yields December each year.

ELECTRIC UTILITIES
HISTORICAL GROWTH RATES

	Company Name	Earnings Growth 5-Year	Dividend Growth 5-Year	Book Value Growth 5-Year
1	Allegheny Energy		-10.0	-1.5
2	Alliant Energy	-1.0	-3.5	1.0
3	Amer. Elec. Power	-1.5	-2.0	-2.0
4	Ameren Corp.	2.5		2.5
5	Aquila Inc.		-11.0	-3.5
6	Avista Corp.	-9.0	-16.5	4.0
7	Black Hills	11.0	4.0	16.5
8	Cen. Vermont Pub. Serv.	6.0	0.5	1.0
9	CenterPoint Energy			
10	CH Energy Group	-2.0		2.0
11	Cinergy Corp.	3.0	0.5	4.0
12	Cleco Corp.	5.0	2.5	4.5
13	CMS Energy Corp.		-5.5	-11.5
14	Consol. Edison	0.5	1.0	2.0
15	Constellation Energy	4.5	-12.5	4.0
16	Dominion Resources	9.5		3.5
17	DPL Inc.		0.5	-4.0
18	Duquesne Light Hldgs	-18.5	-0.5	-16.5
19	DTE Energy			3.5
20	Duke Energy	1.0	0.5	7.5
21	Edison Int'l	1.0		-2.0
22	El Paso Electric	6.5		9.0
23	Empire Dist. Elec.	-5.5		2.0
24	Energy East Corp.	4.0	6.0	4.5
25	Entergy Corp.	8.5	-3.5	5.0
26	Exelon Corp.			
27	FirstEnergy Corp.	2.5		7.0
28	Florida Public Utilities		4.5	6.5
29	FPL Group	4.5	4.0	6.0
30	G't Plains Energy	2.5	0.5	-1.5
31	Green Mountain Pwr.	-9.0	-22.0	-4.5
32	Hawaiian Elec.	3.0	0.5	1.5
33	IDACORP Inc.	-3.0	-0.5	4.0
34	Maine & Maritimes Corp	41.5	1.0	5.5
35	MDU Resources	11.5	4.5	13.5
36	MGE Energy	7.0	1.0	3.5
37	NiSource Inc.	0.5	4.5	11.5
38	Northeast Utilities		-1.0	0.5
39	NorthWestern Corporation-OLD		-2.5	
40	NSTAR	4.5	2.5	2.5
41	OGE Energy	-3.5		1.5
42	Otter Tail Corp.	5.5	2.5	6.0
43	Pepco Holdings			
44	PG&E Corp.	-13.5		-13.0
45	Pinnacle West Capital	1.5	7.5	4.5
46	PNM Resources	4.5	8.0	6.0
47	PPL Corp.	10.5	-3.0	-0.5
48	Progress Energy	6.0	3.0	9.0
49	Public Serv. Enterprise	8.0		-1.5
50	Puget Energy Inc.	-6.0	-6.0	-1.0
51	SCANA Corp.	3.0	-3.0	4.5
52	Sempra Energy	9.0	-8.5	2.0
53	Sierra Pacific Res.		-33.5	-3.5
54	Southern Co.	1.5	1.0	-2.5
55	TECO Energy	-3.0	1.0	2.5
56	TXU Corp.	-4.5	-5.5	-5.5
57	UIL Holdings			2.0
58	UniSource Energy	-10.5		17.5
59	UNITIL Corp.	-4.5	0.5	0.5
60	Vectren Corp.			
61	Westar Energy	-15.0	-12.5	-9.0
62	Wisconsin Energy	9.0	-12.0	2.0
63	WPS Resources	7.0	2.0	5.0
64	Xcel Energy Inc.	-6.0	-4.5	-2.0
	AVERAGE	**1.8**	**-2.5**	**2.0**

Source: Value Line Investment Analyzer 2/2005

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS:ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Amer. Elec. Power	4.0	3.3	4.2	7.5	7.7
2	CH Energy Group					
3	Cinergy Corp.	4.8	4.4	5.0	9.3	9.6
4	Consol. Edison	5.2	2.9	5.3	8.2	8.5
5	Constellation Energy	2.4	9.0	2.6	11.6	11.8
6	Dominion Resources	3.9	5.9	4.1	10.0	10.2
7	DPL Inc.	3.7	4.8	3.9	8.7	8.9
8	Duquesne Light Hldgs	5.3	5.0	5.5	10.5	10.8
9	Duke Energy	4.1	5.3	4.3	9.5	9.8
10	Energy East Corp.	4.3	4.6	4.4	9.0	9.3
11	Exelon Corp.	3.6	5.4	3.7	9.2	9.4
12	FirstEnergy Corp.	4.1	4.1	4.2	8.4	8.6
13	IDACORP Inc.	4.0	4.5	4.2	8.7	8.9
14	NiSource Inc.	4.0	4.4	4.2	8.6	8.8
15	OGE Energy	5.1	3.5	5.3	8.8	9.1
16	PPL Corp.	3.2	5.4	3.3	8.7	8.9
17	Progress Energy	5.4	3.7	5.6	9.2	9.5
18	Public Serv. Enterprise	4.2	4.3	4.4	8.7	8.9
19	Southern Co.	4.3	4.4	4.5	8.9	9.1
20	TECO Energy	4.9	4.1	5.1	9.2	9.5
21	Xcel Energy Inc.	4.7	3.8	4.9	8.7	8.9
	AVERAGE	**4.2**	**4.6**	**4.4**	**9.1**	**9.3**

Notes:
Column 1: Value Line Investment Survey for Windows, 2/2005
Column 2: Zacks long-term earnings growth forecast, 2/2005
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2
Growth forecast unavailable for CH Energy

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1	Amer. Elec. Power	4.0	0.5
2	CH Energy Group	4.5	0.5
3	Cinergy Corp.	4.8	2.0
4	Consol. Edison	5.2	-1.0
5	Constellation Energy	2.4	11.0
6	Dominion Resources	3.9	7.5
7	DPL Inc.	3.7	7.0
8	Duquesne Light Hldgs	5.3	11.0
9	Duke Energy	4.1	-1.5
10	Energy East Corp.	4.3	5.5
11	Exelon Corp.	3.6	6.0
12	FirstEnergy Corp.	4.1	10.0
13	IDACORP Inc.	4.0	1.0
14	NiSource Inc.	4.0	3.0
15	OGE Energy	5.1	5.0
16	PPL Corp.	3.2	4.5
17	Progress Energy	5.4	-2.0
18	Public Serv. Enterprise	4.2	-0.5
19	Southern Co.	4.3	5.0
20	TECO Energy	4.9	6.5
21	Xcel Energy Inc.	4.7	2.5
	AVERAGE	**4.3**	**4.0**

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 2/2005

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Amer. Elec. Power	4.0	0.5	4.1	4.6	4.8
2	CH Energy Group	4.5	0.5	4.5	5.0	5.3
3	Cinergy Corp.	4.8	2.0	4.9	6.9	7.1
4	Constellation Energy	2.4	11.0	2.7	13.7	13.8
5	Dominion Resources	3.9	7.5	4.2	11.7	11.9
6	DPL Inc.	3.7	7.0	4.0	11.0	11.2
7	Duquesne Light Hldgs	5.3	11.0	5.9	16.9	17.2
8	Energy East Corp.	4.3	5.5	4.5	10.0	10.2
9	Exelon Corp.	3.6	6.0	3.8	9.8	10.0
10	FirstEnergy Corp.	4.1	10.0	4.5	14.5	14.7
11	IDACORP Inc.	4.0	1.0	4.0	5.0	5.2
12	NiSource Inc.	4.0	3.0	4.1	7.1	7.3
13	OGE Energy	5.1	5.0	5.4	10.4	10.7
14	PPL Corp.	3.2	4.5	3.3	7.8	8.0
15	Southern Co.	4.3	5.0	4.5	9.5	9.8
16	TECO Energy	4.9	6.5	5.2	11.7	12.0
17	Xcel Energy Inc.	4.7	2.5	4.9	7.4	7.6
	AVERAGE	**4.2**	**5.2**	**4.4**	**9.6**	**9.8**

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 2/2005
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Cinergy Corp.	4.8	2.0	4.9	6.9	7.1
2	Constellation Energy	2.4	11.0	2.7	13.7	13.8
3	Dominion Resources	3.9	7.5	4.2	11.7	11.9
4	DPL Inc.	3.7	7.0	4.0	11.0	11.2
5	Duquesne Light Hldgs	5.3	11.0	5.9	16.9	17.2
6	Energy East Corp.	4.3	5.5	4.5	10.0	10.2
7	Exelon Corp.	3.6	6.0	3.8	9.8	10.0
8	FirstEnergy Corp.	4.1	10.0	4.5	14.5	14.7
9	NiSource Inc.	4.0	3.0	4.1	7.1	7.3
10	OGE Energy	5.1	5.0	5.4	10.4	10.7
11	PPL Corp.	3.2	4.5	3.3	7.8	8.0
12	Southern Co.	4.3	5.0	4.5	9.5	9.8
13	TECO Energy	4.9	6.5	5.2	11.7	12.0
14	Xcel Energy Inc.	4.7	2.5	4.9	7.4	7.6
	AVERAGE	**4.2**	**6.2**	**4.4**	**10.6**	**10.8**
	AVERAGE w/o Duquesne Light					**10.3**

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 2/2005
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

INVESTMENT-GRADE VERTICALLY INTEGRATED ELEC. UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)
1	AES Corp.	0.0	
2	Alliant Energy	3.9	4.0
3	Amer. Elec. Power	4.0	3.3
4	Ameren Corp.	5.0	3.4
5	Black Hills	4.3	6.0
6	Cinergy Corp.	4.8	4.4
7	Cleco Corp.	4.4	
8	CMS Energy Corp.	0.0	
9	Dominion Resources	3.9	5.9
10	DTE Energy	4.7	3.7
11	Edison Int'l	3.1	6.4
12	El Paso Electric	0.0	
13	Empire Dist. Elec.	5.6	5.0
14	Energy East Corp.	4.3	4.6
15	Entergy Corp.	3.1	7.0
16	FirstEnergy Corp.	4.1	4.1
17	FPL Group	3.5	5.1
18	G't Plains Energy	5.5	3.2
19	Green Mountain Pwr.	3.2	
20	Hawaiian Elec.	4.2	3.5
21	IDACORP Inc.	4.0	4.5
22	MGE Energy	3.8	
23	Northeast Utilities	3.6	4.4
24	OGE Energy	5.1	3.5
25	PG&E Corp.	2.6	5.2
26	Pinnacle West Capital	4.6	5.2
27	PNM Resources	2.9	5.0
28	Progress Energy	5.4	3.7
29	Puget Energy Inc.	4.2	5.0
30	SCANA Corp.	3.9	4.5
31	Southern Co.	4.3	4.4
32	TECO Energy	4.9	4.1
33	Wisconsin Energy	2.5	6.1
34	WPS Resources	4.4	4.5
35	Xcel Energy Inc.	4.7	3.8

Notes:

Column 1: Value Line Investment Survey for Windows, 2/2005
Column 2: Zacks long-term earnings growth forecast, 3/2005
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

INVESTMENT-GRADE VERTICALLY INTEGRATED ELEC. UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Alliant Energy	3.9	4.0	4.1	8.1	8.3
2	Amer. Elec. Power	4.0	3.3	4.2	7.5	7.7
4	Ameren Corp.	5.0	3.4	5.2	8.5	8.8
5	Black Hills	4.3	6.0	4.5	10.5	10.8
6	Cinergy Corp.	4.8	4.4	5.0	9.3	9.6
9	Dominion Resources	3.9	5.9	4.1	10.0	10.2
10	DTE Energy	4.7	3.7	4.9	8.5	8.8
11	Edison Int'l	3.1	6.4	3.3	9.7	9.8
13	Empire Dist. Elec.	5.6	5.0	5.9	10.9	11.2
14	Energy East Corp.	4.3	4.6	4.4	9.0	9.3
15	Entergy Corp.	3.1	7.0	3.3	10.3	10.4
16	FirstEnergy Corp.	4.1	4.1	4.2	8.4	8.6
17	FPL Group	3.5	5.1	3.6	8.8	9.0
18	G't Plains Energy	5.5	3.2	5.7	8.9	9.2
20	Hawaiian Elec.	4.2	3.5	4.3	7.8	8.1
21	IDACORP Inc.	4.0	4.5	4.2	8.7	8.9
23	Northeast Utilities	3.6	4.4	3.7	8.1	8.3
24	OGE Energy	5.1	3.5	5.3	8.8	9.1
25	PG&E Corp.	2.6	5.2	2.7	7.9	8.0
26	Pinnacle West Capital	4.6	5.2	4.8	10.0	10.2
27	PNM Resources	2.9	5.0	3.1	8.1	8.2
28	Progress Energy	5.4	3.7	5.6	9.2	9.5
29	Puget Energy Inc.	4.2	5.0	4.4	9.4	9.6
30	SCANA Corp.	3.9	4.5	4.1	8.6	8.8
31	Southern Co.	4.3	4.4	4.5	8.9	9.1
32	TECO Energy	4.9	4.1	5.1	9.2	9.5
33	Wisconsin Energy	2.5	6.1	2.7	8.8	9.0
34	WPS Resources	4.4	4.5	4.6	9.1	9.3
35	Xcel Energy Inc.	4.7	3.8	4.9	8.7	8.9
	AVERAGE	**4.2**	**4.6**	**4.3**	**9.0**	**9.2**

Notes:
Column 1: Value Line Investment Survey for Windows, 2/2005
Column 2: Zacks long-term earnings growth forecast, 3/2005
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

INVESTMENT-GRADE VERT. INTEGR. ELEC. UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1	AES Corp.	0.0	5.0
2	Alliant Energy	3.9	3.0
3	Amer. Elec. Power	4.0	0.5
4	Ameren Corp.	5.0	-0.5
5	Black Hills	4.3	-2.0
6	Cinergy Corp.	4.8	2.0
7	Cleco Corp.	4.4	1.0
8	CMS Energy Corp.	0.0	
9	Dominion Resources	3.9	7.5
10	DTE Energy	4.7	7.5
11	Edison Int'l	3.1	4.5
12	El Paso Electric	0.0	10.5
13	Empire Dist. Elec.	5.6	6.5
14	Energy East Corp.	4.3	5.5
15	Entergy Corp.	3.1	7.0
16	FirstEnergy Corp.	4.1	10.0
17	FPL Group	3.5	4.0
18	G't Plains Energy	5.5	4.0
19	Green Mountain Pwr.	3.2	3.5
20	Hawaiian Elec.	4.2	4.0
21	IDACORP Inc.	4.0	1.0
22	MGE Energy	3.8	6.0
23	Northeast Utilities	3.6	8.5
24	OGE Energy	5.1	5.0
25	PG&E Corp.	2.6	17.5
26	Pinnacle West Capital	4.6	1.5
27	PNM Resources	2.9	
28	Progress Energy	5.4	-2.0
29	Puget Energy Inc.	4.2	8.5
30	SCANA Corp.	3.9	5.5
31	Southern Co.	4.3	5.0
32	TECO Energy	4.9	6.5
33	Wisconsin Energy	2.5	4.5
34	WPS Resources	4.4	4.0
35	Xcel Energy Inc.	4.7	2.5
	AVERAGE	**3.8**	**4.8**

Notes:

Column 1, 2: Value Line Investment Survey for Windows, 2/
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

INVESTMENT-GRADE VERTICALLY INTEGRATED ELEC. UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Alliant Energy	3.9	3.0	4.0	7.0	7.3
2	Amer. Elec. Power	4.0	0.5	4.1	4.6	4.8
3	Cinergy Corp.	4.8	2.0	4.9	6.9	7.1
4	Cleco Corp.	4.4	1.0	4.5	5.5	5.7
5	Dominion Resources	3.9	7.5	4.2	11.7	11.9
6	DTE Energy	4.7	7.5	5.0	12.5	12.8
7	Edison Int'l	3.1	4.5	3.2	7.7	7.9
8	Empire Dist. Elec.	5.6	6.5	6.0	12.5	12.8
9	Energy East Corp.	4.3	5.5	4.5	10.0	10.2
10	Entergy Corp.	3.1	7.0	3.3	10.3	10.4
11	FirstEnergy Corp.	4.1	10.0	4.5	14.5	14.7
12	FPL Group	3.5	4.0	3.6	7.6	7.8
13	G't Plains Energy	5.5	4.0	5.7	9.7	10.0
14	Green Mountain Pwr.	3.2	3.5	3.3	6.8	7.0
15	Hawaiian Elec.	4.2	4.0	4.4	8.4	8.6
16	IDACORP Inc.	4.0	1.0	4.0	5.0	5.2
17	MGE Energy	3.8	6.0	4.0	10.0	10.3
18	Northeast Utilities	3.6	8.5	3.9	12.4	12.6
19	OGE Energy	5.1	5.0	5.4	10.4	10.7
20	PG&E Corp.	2.6	17.5	3.0	20.5	20.7
21	Pinnacle West Capital	4.6	1.5	4.6	6.1	6.4
22	Puget Energy Inc.	4.2	8.5	4.5	13.0	13.3
23	SCANA Corp.	3.9	5.5	4.1	9.6	9.8
24	Southern Co.	4.3	5.0	4.5	9.5	9.8
25	TECO Energy	4.9	6.5	5.2	11.7	12.0
26	Wisconsin Energy	2.5	4.5	2.7	7.2	7.3
27	WPS Resources	4.4	4.0	4.5	8.5	8.8
28	Xcel Energy Inc.	4.7	2.5	4.9	7.4	7.6
	AVERAGE	**4.1**	**5.2**	**4.3**	**9.5**	**9.8**

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 2/2005
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

INVESTMENT-GRADE VERTICALLY INTEGRATED ELEC. UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Alliant Energy	3.9	3.0	4.0	7.0	7.3
3	Cinergy Corp.	4.8	2.0	4.9	6.9	7.1
5	Dominion Resources	3.9	7.5	4.2	11.7	11.9
6	DTE Energy	4.7	7.5	5.0	12.5	12.8
7	Edison Int'l	3.1	4.5	3.2	7.7	7.9
8	Empire Dist. Elec.	5.6	6.5	6.0	12.5	12.8
9	Energy East Corp.	4.3	5.5	4.5	10.0	10.2
10	Entergy Corp.	3.1	7.0	3.3	10.3	10.4
11	FirstEnergy Corp.	4.1	10.0	4.5	14.5	14.7
12	FPL Group	3.5	4.0	3.6	7.6	7.8
13	G't Plains Energy	5.5	4.0	5.7	9.7	10.0
14	Green Mountain Pwr.	3.2	3.5	3.3	6.8	7.0
15	Hawaiian Elec.	4.2	4.0	4.4	8.4	8.6
17	MGE Energy	3.8	6.0	4.0	10.0	10.3
18	Northeast Utilities	3.6	8.5	3.9	12.4	12.6
19	OGE Energy	5.1	5.0	5.4	10.4	10.7
20	PG&E Corp.	2.6	17.5	3.0	20.5	20.7
21	Pinnacle West Capital	4.6	1.5	4.6	6.1	6.4
22	Puget Energy Inc.	4.2	8.5	4.5	13.0	13.3
23	SCANA Corp.	3.9	5.5	4.1	9.6	9.8
24	Southern Co.	4.3	5.0	4.5	9.5	9.8
25	TECO Energy	4.9	6.5	5.2	11.7	12.0
26	Wisconsin Energy	2.5	4.5	2.7	7.2	7.3
27	WPS Resources	4.4	4.0	4.5	8.5	8.8
28	Xcel Energy Inc.	4.7	2.5	4.9	7.4	7.6
	AVERAGE	**4.1**	**5.8**	**4.3**	**10.1**	**10.3**
	AVERAGE w/o PG&E					**9.9**

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 2/2005
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

NATURAL GAS UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	Industry (1)	% Current Divid Yield (2)	Analysts Growth Forecast (3)	Expected Divid Yield (4)	Cost of Equity (5)	ROE (6)
1	AGL Resources	GASDISTR	3.3	5.5	3.5	9.0	9.2
2	Atmos Energy	GASDISTR	4.4	4.8	4.6	9.3	9.6
3	Energen Corp.	GASDISTR	1.3	6.9	1.4	8.3	8.4
4	KeySpan Corp.	GASDISTR	4.6	5.1	4.8	10.0	10.2
5	Laclede Group	GASDISTR	4.5	5.0	4.8	9.8	10.0
6	New Jersey Resources	GASDISTR	3.1	6.2	3.3	9.5	9.7
7	NICOR Inc.	GASDISTR	5.0	3.2	5.2	8.3	8.6
8	Northwest Nat. Gas	GASDISTR	3.9	5.1	4.1	9.2	9.4
9	Peoples Energy	GASDISTR	5.1	4.5	5.3	9.8	10.1
10	Piedmont Natural Gas	GASDISTR	3.7	4.8	3.8	8.6	8.8
11	South Jersey Inds.	GASDISTR	3.1	4.7	3.3	7.9	8.1
12	Southwest Gas	GASDISTR	3.2	4.6	3.4	8.0	8.1
13	UGI Corp.	GASDISTR	3.0	7.0	3.2	10.2	10.4
14	WGL Holdings Inc.	GASDISTR	4.3	3.9	4.4	8.3	8.5
	AVERAGE		**3.7**	**5.1**	**3.9**	**9.0**	**9.2**

Notes:
Column 1, 2: Value Line Investment Analyzer, 2/2005
Column 3: Zacks long-term earnings growth forecast, 3/2005
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3

NATURAL GAS UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH FORECASTS

	Company	Industry (1)	% Current Divid Yield (2)	Value Line Proj Growth (3)	Expected Divid Yield (4)	Cost of Equity (5)	ROE (6)
1	AGL Resources	GASDISTR	3.3	5.0	3.5	8.5	8.7
2	Atmos Energy	GASDISTR	4.4	5.0	4.6	9.6	9.9
3	Energen Corp.	GASDISTR	1.3	10.0	1.5	11.5	11.6
4	KeySpan Corp.	GASDISTR	4.6	4.0	4.8	8.8	9.0
5	Laclede Group	GASDISTR	4.5	5.5	4.8	10.3	10.5
6	New Jersey Resources	GASDISTR	3.1	6.5	3.3	9.8	10.0
7	NICOR Inc.	GASDISTR	5.0	1.5	5.1	6.6	6.9
8	Northwest Nat. Gas	GASDISTR	3.9	5.5	4.1	9.6	9.8
9	Peoples Energy	GASDISTR	5.1	1.0	5.1	6.1	6.4
10	Piedmont Natural Gas	GASDISTR	3.7	7.0	3.9	10.9	11.1
11	South Jersey Inds.	GASDISTR	3.1	6.5	3.3	9.8	10.0
12	Southwest Gas	GASDISTR	3.2	11.0	3.6	14.6	14.8
13	UGI Corp.	GASDISTR	3.0	12.0	3.3	15.3	15.5
14	WGL Holdings Inc.	GASDISTR	4.3	4.5	4.4	8.9	9.2
	AVERAGE		**3.7**	**6.1**	**3.9**	**10.0**	**10.2**

Notes:
Column 1, 2, 3: Value Line Investment Analyzer, 2/2005
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3

	Company	S&P Credit Rating	Bond Rating Score	Business Profile	Parent
	1. Distribution Utilities				
1	Atlanta Gas Light Co	A-/Stable/--	5	2	AGL Resources Inc
2	Potomac Edison Co.	BB-/Stable/--	11	3	Allegheny Energy Inc
3	West Penn Power Co.	BB-/Stable/--	11	3	Allegheny Energy Inc
4	Central Illinois Public Service Co.	A-/CW-Neg/--	5	3	Ameren
5	AEP Texas North Co	BBB/Stable/-□	7	2	American Electric Power
6	AEP Texas Central Co	BBB/Stable/-□	7	2	American Electric Power
7	Ohio Power Co	BBB/Stable/-	7	3	American Electric Power
8	Columbus Southem Power Co.	BBB/Stable/-	7	3	American Electric Power
9	American States Water Co	A/Negative/--	5	3	American States Water Co
10	Southern California Water Co.	A/Negative/--	5	3	American States Water Co
11	American Water Capital Corp	A/Negative/	5	2	American Water Works Co
12	Aqua Pennsylvania	A+/Stable/--	3	2	Aqua America Inc
13	Aquarion Water Co. of Connecticut	A/Stable/--	4	2	Aquarion
14	California Water Service Co	A+/Negative/--	3	3	California Water Service Gro
15	Cascade Natural Gas Corp	BBB+/Stable/--	6	2	Cascade Natural Gas Corp
16	CenterPoint Energy Houston Electric LLc	BBB/Negative/-	8	3	CenterPoint Energy
17	CenterPoint Energy Resources Corp.LLC	BBB/Negative/-	8	3	CenterPoint Energy
18	Central Hudson Gas & Electric Co.	A/Stable/--	4	3	CH Energy Group
19	Atlantic City Sewerage Co.	A/Stable/--	4	3	City of Atlantic City
20	Connecticut Water Co.	A/Stable/--	4	2	Connecticut Water Service In
21	Connecticut Water Service Inc.	A/Stable/--	4	2	Connecticut Water Service In
22	Consolidated Edison Inc.	A/Stable/A-1	4	2	Consolidated Edison
23	Orange and Rockland Utilities Inc.	A/Stable/A-1	4	2	Consolidated Edison
24	Consolidated Edison Co. of New York	A/Stable/A-1	4	2	Consolidated Edison
25	Baltimore Gas & Electric Co	BBB+/Stable/A-2	6	3	Constellation Energy
26	Duquesne Light Holdings Inc.	BBB/Negative/ -	8	5	Duquesne Light Holdings Inc
27	Duquesne Light Co	BBB/Negative/	8	4	Duquesne Light Holdings Inc
28	Illinova Corp	BB-/Negative/--	11	7	Dynegy Inc.
29	Alabama Gas Corp.	A-/Stable/--	5	2	Energen
30	Central Maine Power Co.	BBB+/Negative/-	6	3	Energy East Corporation
31	Connecticut Natural Gas Corp.	BBB+/Negative/-	6	3	Energy East Corporation
32	Southern Connecticut Gas Co.	BBB+/Negative/-	6	3	Energy East Corporation
33	Commonwealth Edison Co.	A-/Negative/A-2	5	4	Exelon
34	PECO Energy Co.	A-/Negative/A-2	5	4	Exelon
35	Ferrellgas Partners L.P.	BB-/Negative/--	11	8	Ferrellgas Partners L.P.
36	Jersey Central Power & Light Co.	BBB-/Stable/-	8	4	FirstEnergy
37	Metropolitan Edison Co	BBB-/Stable/--	8	4	FirstEnergy
38	Pennsylvania Electric Co.	BBB-/Stable/--	8	4	FirstEnergy
39	Aquarion Co.	A/Stable/--	4	2	Kelda Group Plc
40	KeySpan Energy Delivery Long Island	A+/Negative/--	3	1	KeySpan
41	KeySpan Energy Delivery New York	A+/Negative/--	3	1	KeySpan
42	Boston Gas CO	A/Negative/--	5	2	KeySpan
43	Colonial Gas Co.	A/Negative/--	5	2	KeySpan
44	Laclede Group Inc.	A/Stable/--	4	3	Laclede
45	Laclede Gas Co.	A/Stable/A-1	4	3	Laclede
46	Middlesex Water Co	A/Negative/--	5	3	Middlesex Water Co
47	Niagara Mohawk Power Corp.	A/Stable/--	4	3	National Grid
48	Narragansett Electric Co.	A/Stable/A-1	4	1	National Grid
49	National Grid USA	A/Stable/A-1	4	2	National Grid USA

50	Massachusetts Electric Co.	A/Stable/A-1	4	1	New England Electric Systen
51	New Jersey Natural Gas Co	A+/Stable/A-1	3	1	New Jersey Resources
52	Nicor Gas Co.	AA/Stable/A-1+	1	2	Nicor Inc
53	Nicor Inc	AA/Stable/A-1+	1	3	Nicor Inc
54	Bay State Gas Co.	BBB/Stable/-	7	2	NiSource
55	Yankee Gas Services Co.	BBB+/Negative/-	6	3	Northeast Utilities
56	Western Massachusetts Electric Co	BBB+/Stable/--	6	1	Northeast Utilities System
57	Connecticut Light & Power Co.	BBB+/Negativel-	6	3	Northeast Utilities System
58	Northwest Natural Gas Co.	A/Stable/A-1	4	1	Northwest Natural Gas Co.
59	NorthWestern Corp.	D/NM/--		7	NorthWestern Corp.
60	NSTAR	A/Stable/A-1	4	1	NSTAR
61	Boston Edison Co.	A/Stable/A-1	4	1	NSTAR
62	Commonwealth Electric Co	A/Stable/--	4	1	NSTAR
63	NSTAR Gas Co.	A/Stable/--	4	2	NSTAR
64	Cambridge Electric Light Co.	A/Stable/--	4	1	NSTAR
65	NUI Utilities Inc	BB/CW-Dev/-	10	4	NUI Corporation
66	ONEOK Inc.	A-/Stable/A-2	5	6	ONEOK Inc.
67	Rockland Electric Co	A/Stable/--	4	2	Orange and Rockland Utilitie
68	Peoples Gas Light & Coke Co.	A-/Stable/A-2	5	2	Peoples Energy
69	North Shore Gas Co.	A-/Stable/A-2	5	2	Peoples Energy
70	Delmarva Power & Light Co	BBB+/Negative/	6	3	PEPCO Holdings
71	Atlantic City Electric Co.	BBB+/Negative/	6	3	PEPCO Holdings
72	Potomac Electric Power Co.	BBB+/Negative/	6	3	PEPCO Holdings
73	Piedmont Natural Gas Co. Inc.	A/Stable/A-1	4	2	Piedmont Natural Gas
74	PPL Electric Utilities Corp.	A-/Negative/--	5	4	PPL Corp
75	Baton Rouge Water Works Co.	AA/Stable/--	1	1	Private
76	Public Service Electric & Gas Co	BBB/Stable/A-2	7	3	Public Service Enterprise Grc
77	Questar Gas Co	A+/Negative/--	3	3	Questar
78	Public Service Co. of North Carolina Inc.	A-/Stable/A-2	5	2	SCANA Corp.
79	SEMCO Energy Inc	BB-/Negative/--	11	5	Semco Energy
80	Southern California Gas Co	A/Stable/A-1	4	1	Sempra Energy
81	South Jersey Gas Co	BBB+/Stable/--	6	2	South Jersey Industries
82	Southern Union Co	BBB/Negative/-	8	3	Southern Union
83	Southwest Gas Corp.	BBB-/Stable/--	7	3	Southwest Gas
84	Star Gas Partners L.P.	BB-/Stable/--	11	8	Star Gas Partners L.P.
85	Suburban Propane Partners L.P.	BB-/Stable/--	11	8	Suburban Propane Partners
86	Elizabethtown Water Co	A+/Negative/--	3	2	Thames Water Co
87	Texas-New Mexico Power Co.	BB+/Stable/-	9	4	TNP Enterprises
88	TXU Gas Co	BBB/CW-Dev/-	8	3	TXU
89	Oncor Electric Delivery Co.	BBB/Negative/-	8	2	TXU
90	AmeriGas Partners L.P.	BB+/Stable/-	9	7	UGI
91	UGI Utilities Inc	BBB+/Negativel-	6	4	UGI
92	United Water New Jersey	A/Negative/--	5	4	United Water Resources
93	United Waterworks	A-/Negative/--	5	4	United Water Resources
94	Indiana Gas Co. Inc.	A/Negative/--	5	1	Vectren
95	WGL Holdings Inc.	AA/Stable/A-1+	3	3	WGL Holdings
96	Washington Gas Light Co.	AA/Stable/A-1+	1	2	WGL Holdings
97	Wisconsin Gas Co.	A-/Stable/A-2	5	2	Wisconsin Energy Corp
98	York Water Co. (The)	A-/Stable/--	5	2	York Water Co.
	AVERAGE		**5.6**	**2.9**	

Source: Standard & Poor's "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised," June 2004.

DISTRIBUTION UTILITIES
BETA RISK MEASURES

	Company Name	Industry	Beta
1	AGL Resources	GASDISTR	0.80
2	Allegheny Energy	UTILEAST	1.60
3	Amer. Elec. Power	UTILCENT	1.15
4	Amer. States Water	WATER	0.70
5	Ameren Corp.	UTILCENT	0.75
6	Aqua America	WATER	0.75
7	California Water	WATER	0.75
8	Cascade Natural Gas	GASDISTR	0.75
9	CenterPoint Energy	UTILCENT	0.55
10	CH Energy Group	UTILEAST	0.80
11	Conn. Water Services	WATER	0.65
12	Consol. Edison	UTILEAST	0.60
13	Duquesne Light Hldgs	UTILEAST	0.75
14	Dynegy Inc. 'A'	GASDIVRS	2.50
15	Energen Corp.	GASDIVRS	0.70
16	Energy East Corp.	UTILEAST	0.80
17	Exelon Corp.	UTILEAST	0.70
18	Ferrellgas Partners L P	GASDISTR	0.55
19	FirstEnergy Corp.	UTILEAST	0.75
20	KeySpan Corp.	GASDISTR	0.80
21	Laclede Group	GASDISTR	0.70
22	Middlesex Water	WATER	0.65
23	New Jersey Resources	GASDISTR	0.75
24	NICOR Inc.	GASDISTR	1.05
25	Northeast Utilities	UTILEAST	0.75
26	Northwest Nat. Gas	GASDISTR	0.65
27	NSTAR	UTILEAST	0.70
28	ONEOK Inc.	GASDIVRS	0.90
29	Peoples Energy	GASDISTR	0.80
30	Pepco Holdings	UTILEAST	0.85
31	Piedmont Natural Gas	GASDISTR	0.75
32	PPL Corp.	UTILEAST	0.95
33	Public Serv. Enterprise	UTILEAST	0.85
34	Questar Corp.	GASDIVRS	0.85
35	SCANA Corp.	UTILEAST	0.70
36	SEMCO Energy	GASDISTR	0.65
37	Sempra Energy	UTILWEST	0.90
38	South Jersey Inds.	GASDISTR	0.55
39	Southern Union	GASDISTR	0.95
40	Southwest Gas	GASDISTR	0.80
41	Star Gas Partners L P	GASDISTR	0.70
42	Suburban Propane Partn	GASDISTR	0.60
43	TXU Corp.	UTILCENT	1.00
44	UGI Corp.	GASDISTR	0.75
45	Vectren Corp.	UTILCENT	0.75
46	WGL Holdings Inc.	GASDISTR	0.75
47	Wisconsin Energy	UTILCENT	0.70
	MEDIAN		0.75

Source: VLIA 2/2005

NATURAL GAS DISTRIBUTION INDUSTRY
VALUE LINE BETAS

	Company Name	Industry	Beta
1	AGL Resources	GASDISTR	0.80
2	AmeriGas Partners	GASDISTR	0.60
3	Atmos Energy	GASDISTR	0.70
4	Energen Corp.	GASDIVRS	0.70
5	Ferrellgas Partners L P	GASDISTR	0.55
6	KeySpan Corp.	GASDISTR	0.80
7	New Jersey Resources	GASDISTR	0.75
8	NICOR Inc.	GASDISTR	1.05
9	Northwest Nat. Gas	GASDISTR	0.65
10	Peoples Energy	GASDISTR	0.80
11	Piedmont Natural Gas	GASDISTR	0.75
12	South Jersey Inds.	GASDISTR	0.55
13	Southern Union	GASDISTR	0.95
14	Southwest Gas	GASDISTR	0.80
15	Suburban Propane Partners	GASDISTR	0.60
16	UGI Corp.	GASDISTR	0.75
17	WGL Holdings Inc.	GASDISTR	0.75
	MEDIAN		0.75

Source: Value Line Investment Analyzer 2/2005

4. Diversified Energy

5

	Company	S&P Credit Rating	Bond Rating Score	Business Profile	Parent
1	Allegheny Energy Inc	B/Stablel/--	13	7	Allegheny Energy Inc
2	Alliant Energy Corp.	BBB+/Negative/A	6	6	Alliant Energy Corp.
3	American Electric Power Co. Inc.	BBB/Stable/A-2	7	6	American Electric Power Co
4	Aquila Inc.	B-/Negative/--	14	8	Aquila
5	Avista Corp.	BB+/Stable/-	9	6	Avista Corp.
6	Black Hills Corp	BBB-/Negative/--	8	8	Black Hills Corp
7	Centerpoint Energy Inc	BBB/Negative/--	8	5	Centerpoint
8	Cinergy Corp.	BBB+/Stable/A-2	6	7	Cinergy Corp.
9	ClecoCorp	BBB/Negative/A-:	8	6	ClecoCorp
10	CMS Energy Corp.	BB/Negative/--	11	7	CMS Energy
11	Constellation Energy Group Inc.	BBB+/Stable/A-2	6	7	Constellation Energy
12	Dominion Resources Inc.	BBB+/Negative/A	6	7	Dominion Resources Inc.
13	DPL Inc	BB-/CW-Neg/--	11	8	DPL Inc
14	DTE Energy Co.	BBB+/Negative/A	6	6	DTE Energy Co.
15	Duke Capital Corp.	BBB/Stable/A-2	7	8	Duke Energy
16	Duke Energy Corp	BBB/Stable/A-2	7	7	Duke Energy Corp
17	Dynergy Holdings Inc	B/Negative/--	14	9	Dynergy Inc
18	Dynergy Inc	B/Negative/--	14	8	Dynergy Inc
19	Edison International	BB+/Stable/-	9	6	Edison International
20	El Paso CGP Corp	B-/Negative/--	14	6	EL Paso
21	El Paso Corp.	B-/Negative/--	14	8	El Paso Corp.
22	Entergy Corp	BBB/Stable/--	7	6	Entergy Corp
23	Exelon Corp	A-/Negative/A-2	5	7	Exelon Corp
24	First Energy Corp	BBB-/Stable/--	8	6	First Energy Corp
25	FPL Group Inc.	A/Negative/--	5	5	FPL Group Inc.
26	Great Plains Energy Inc.	BBB/Stable/--	7	7	Great Plains Energy Inc.
27	Hawaiian Electric Industries Inc	BBB/Stable/A-2	7	6	Hawaiian Electric Industries Ir
28	KeySpan Corp.	A/Negative/A-1	5	6	KeySpan
29	Kinder Morgan Energy Partners L.P.	BBB+/Stable/A-2	6	5	Kinder Morgan
30	Kinder Morgan Inc.	BBB/Stable/A-2	7	5	Kinder Morgan Energy
31	Centennial Energy Holdings Inc.	A-/Negative/A-2	5	8	MDU
32	MDU Resources Group Inc.	A-/Negative/A-2	5	8	MDU Resources Group Inc.
33	MidAmerican Energy Holdings Co.	BBB/Positive/--	6	5	MidAmerican Energy Holdings
34	New York Water Service Corp.	BB/Stable	10	7	New York Water Authority
35	Northeast Utilities	BBB+/Stable/--	6	6	Northeast Utilities
36	OGE Energy Corp.	BBB+/Stable/A-2	6	6	OGE Energy Corp.
37	Otter Tail Corp.	A-/Negative/--	5	4	Otter Tail Corp.
38	Peoples Energy Corp.	A-/Stable/A-2	5	4	Peoples Energy Corp.
39	Potomac Capital Investment Corp.	BBB/Negative/--	8	8	PEPCO
40	Conectiv	BBB+/Negative/--	6	5	PEPCO Holdings
41	Pepco Holdings Inc	BBB+/Stable/A-2	6	5	Pepco Holdings Inc
42	TNPEnterprises	BB+/Stable/-	9	6	PNM Resources
43	LG&E Energy Corp.	BBB+/Stable/--	6	6	Powergen US Holdings
44	PPL Corp.	BBB/Stable/--	7	7	PPL Corp.
45	Progress Energy Inc.	BBB/Stable/A-2	7	6	Progress Energy Inc.
46	Public Service Enterprise Group Inc.	BBB/Stable/A-2	7	7	Public Service Enterprise Gro
47	PacifiCorp Holdings Inc.	A-/Negative/--	5	7	Scottish Power Holdings
48	TECO Energy Inc	BBB-/Negative/A-	8	5	TECO Energy Inc
49	TXU Corp	BBB/Negative/--	8	5	TXU Corp
50	Vectren Corp.	A-/Negative/--	5	5	Vectren Corp.
51	Williams Companies Inc.	B+/Negative/--	12	8	Williams Companies Inc.
52	WPS Resources Corp.	A/Stable/A-1	4	4	WPS Resources Corp.
	AVERAGE		7.7	6.4	

Source: Standard & Poor's "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised," June 2004.

DIVERSIFIED ENERGY UTILITIES
BETA RISK MEASURES

	Company Name	Industry	Beta
1	Allegheny Energy	UTILEAST	1.60
2	Alliant Energy	UTILCENT	0.80
3	Amer. Elec. Power	UTILCENT	1.15
4	Aquila Inc.	UTILCENT	1.25
5	Avista Corp.	UTILWEST	0.90
6	Black Hills	UTILWEST	0.95
7	CenterPoint Energy	UTILCENT	0.55
8	Cinergy Corp.	UTILCENT	0.80
9	Cleco Corp.	UTILCENT	1.10
10	CMS Energy Corp.	UTILCENT	1.30
11	Constellation Energy	UTILEAST	0.85
12	Dominion Resources	UTILEAST	0.85
13	DPL Inc.	UTILCENT	0.90
14	DTE Energy	UTILCENT	0.70
15	Duke Energy	UTILEAST	1.10
16	Dynegy Inc. 'A'	GASDIVRS	2.50
17	Edison Int'l	UTILWEST	1.05
18	El Paso Corp.	GASDIVRS	1.85
19	Entergy Corp.	UTILCENT	0.75
20	Exelon Corp.	UTILEAST	0.70
21	FirstEnergy Corp.	UTILEAST	0.75
22	FPL Group	UTILEAST	0.70
23	G't Plains Energy	UTILCENT	0.80
24	Hawaiian Elec.	UTILWEST	0.65
25	KeySpan Corp.	GASDISTR	0.80
26	Kinder Morgan	GASDIVRS	0.80
27	Kinder Morgan Energy	GASDIVRS	0.70
28	MDU Resources	UTILWEST	0.85
29	Northeast Utilities	UTILEAST	0.75
30	OGE Energy	UTILCENT	0.70
31	Otter Tail Corp.	UTILCENT	0.60
32	Peoples Energy	GASDISTR	0.80
33	Pepco Holdings	UTILEAST	0.85
34	PNM Resources	UTILWEST	0.85
35	PPL Corp.	UTILEAST	0.95
36	Progress Energy	UTILEAST	0.80
37	Public Serv. Enterprise	UTILEAST	0.85
38	TECO Energy	UTILEAST	0.90
39	TXU Corp.	UTILCENT	1.00
40	Vectren Corp.	UTILCENT	0.75
41	Williams Cos.	GASDIVRS	2.40
42	WPS Resources	UTILCENT	0.75
	MEDIAN		0.85

Source: VLIA 2/2005

DIVERSIFIED ELECTRIC UTILITIES
BETA RISK MEASURES

	Company Name	Industry	Beta
1	Allegheny Energy	UTILEAST	1.60
2	Alliant Energy	UTILCENT	0.80
3	Amer. Elec. Power	UTILCENT	1.15
4	Aquila Inc.	UTILCENT	1.25
5	Avista Corp.	UTILWEST	0.90
6	Black Hills	UTILWEST	0.95
7	CenterPoint Energy	UTILCENT	0.55
8	Cinergy Corp.	UTILCENT	0.80
9	Cleco Corp.	UTILCENT	1.10
10	CMS Energy Corp.	UTILCENT	1.30
11	Constellation Energy	UTILEAST	0.85
12	Dominion Resources	UTILEAST	0.85
13	DPL Inc.	UTILCENT	0.90
14	DTE Energy	UTILCENT	0.70
15	Duke Energy	UTILEAST	1.10
16	Edison Int'l	UTILWEST	1.05
17	Entergy Corp.	UTILCENT	0.75
18	Exelon Corp.	UTILEAST	0.70
19	FirstEnergy Corp.	UTILEAST	0.75
20	FPL Group	UTILEAST	0.70
21	G't Plains Energy	UTILCENT	0.80
22	Hawaiian Elec.	UTILWEST	0.65
23	MDU Resources	UTILWEST	0.85
24	Northeast Utilities	UTILEAST	0.75
25	OGE Energy	UTILCENT	0.70
26	Otter Tail Corp.	UTILCENT	0.60
27	Pepco Holdings	UTILEAST	0.85
28	PNM Resources	UTILWEST	0.85
29	PPL Corp.	UTILEAST	0.95
30	Progress Energy	UTILEAST	0.80
31	Public Serv. Enterprise	UTILEAST	0.85
32	TECO Energy	UTILEAST	0.90
33	TXU Corp.	UTILCENT	1.00
34	Vectren Corp.	UTILCENT	0.75
35	WPS Resources	UTILCENT	0.75
	MEDIAN		0.85

Source: VLIA 2/2005

OIL & GAS PRODUCERS
BETA ESTIMATES

	Company Name	Industry	Beta	Safety Rank	Financial Strength
1	Apache Corp.	OILPROD	0.85	3	B++
2	Burlington Resources	OILPROD	0.80	3	B++
3	Anadarko Petroleum	OILPROD	0.90	3	B+
4	Pioneer Natural Res.	OILPROD	0.95	3	B
5	Chesapeake Energy	OILPROD	0.90	3	B+
6	Ultra Petroleum Corp.	OILPROD	0.80	3	B++
7	Noble Energy	OILPROD	0.90	3	B
8	Pogo Producing	OILPROD	0.90	3	B++
9	Forest Oil	OILPROD	1.00	3	B+
10	Unit Corp.	OILPROD	1.00	3	B++
11	Houston Expl Co	OILPROD	1.00	3	B++
12	Cimarex Energy Co.	OILPROD	0.95	2	A
13	Magnum Hunter Resources	OILPROD	0.60	3	B+
14	St. Mary Land & Expl	OILPROD	0.70	3	B++
15	Encore Acquisition	OILPROD	1.00	3	B+
16	Berry Petroleum `A'	OILPROD	0.70	3	B+
17	Stone Energy	OILPROD	0.90	3	B++
18	Spinnaker Exploration Co	OILPROD	0.65	3	B+
19	Hugoton Royalty Trust	OILPROD	0.55	2	A
20	Comstock Resources	OILPROD	0.90	3	B
21	Remington Oil & Gas Corp	OILPROD	0.85	3	B++
22	Swift Energy	OILPROD	1.10	3	B
23	Energy Partners Ltd	OILPROD	0.75	3	B+
24	Delta Petroleum	OILPROD	0.75	3	B+
	AVERAGE		0.85		

Source: Value Line Investment Survey for Windows 2/2005